Annual Information Form

For the Year Ended December 31, 2018
Dated March 12, 2019

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SELECT DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this Annual Information Form. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended;

"**AIF**" or "**Annual Information Form**" means this annual information form;

"**Audit Committee**" means the audit committee of the Board;

"**Board of Directors**" or "**Board**" means the board of directors of the Corporation;

"**COGE Handbook**" means the "Canadian Oil and Gas Evaluation Handbook" maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

"**Common Shares**" means the common shares of the Corporation;

"**Corporation**" or "**Surge**" means Surge Energy Inc., a corporation amalgamated under the ABCA;

"**Credit Facility**" means the $550 million extendible revolving term credit facility of the Corporation with a banking syndicate led by National Bank of Canada, as amended from time to time;

"**Debentures**" means the 5.75% convertible unsecured subordinated debentures due on December 31, 2022, as more particularly described under the heading "*Description of Capital Structure*";

"**IFRS**" means International Financial Reporting Standards, as issued by the International Accounting Standards Board, as amended from time to time;

"**Indenture**" means the debenture indenture between Surge and Computershare Trust Company of Canada under which the Debentures are issued;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**Reserves Report**" means the independent engineering report dated February 27, 2019 and effective December 31, 2018 prepared by and containing the evaluation of Sproule of the oil, NGL and natural gas reserves attributable to the properties of the Corporation;

"**Sproule**" means Sproule Associates Limited, independent oil and gas reservoir engineers;

"**TSX**" means the Toronto Stock Exchange; and

"**U.S.**" or "**United States**" means the United States of America.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All dollar amounts set forth in this Annual Information Form, including "dollar", "$" and "CAD$" are in Canadian dollars, except where otherwise indicated. "US$" means United States dollars.

ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

bbl	Barrel
bbls	Barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
bbl/d	barrels per day
NGLs	natural gas liquids
stb	stock tank barrel

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

Other

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 35.1° API or greater is generally referred to as light crude oil. Liquid petroleum with a specified gravity of 25.8° to 35° API or greater is generally referred to as medium crude oil. Liquid petroleum with a specified gravity of 25.7° API or lower is generally referred to as heavy crude oil.
boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
boe/d	barrel of oil equivalent per day
m^3	cubic metres
Mboe	1,000 barrels of oil equivalent
MMboe	1,000,000 barrels of oil equivalent
$000s	thousands of dollars
M$ or $M	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NON-IFRS MEASURES

This AIF contains the term "netback" which is not defined by IFRS and therefore may not be comparable to performance measures presented by others. In this AIF, "netback" is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Management believes that in addition to net income, netbacks are a useful supplemental measure as it assists in the determination of the Corporation's operating performance. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Corporation's performance.

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of the Corporation's natural gas and petroleum reserves does not represent the fair market value of the Corporation's reserves.

Caution Respecting Boe

In this AIF, the abbreviation boe means barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas when converting natural gas to boes. **Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

Definitions

Certain terms used in this AIF in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this AIF, but not defined or described, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities" (which refers to the lowest level at which reserves calculations are performed) and to "reported reserves" (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories as follows:

"**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing as follows:

"**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Interests in Reserves, Production, Wells and Properties

"**gross**" means: (i) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (ii) in relation to wells, the total number of wells in which an issuer has an interest; and (iii) in relation to properties, the total area of properties in which an issuer has an interest.

"**net**" means: (i) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (ii) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (iii) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.

"**working interest**" means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the issuer the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Description of Exploration and Development Wells and Costs

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (ii) drill, complete and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (iii) dry hole contributions and bottom hole contributions; (iv) costs of drilling, completing and equipping exploratory wells; and (v) costs of drilling exploratory type stratigraphic test wells.

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements or disclosures contained in this Annual Information Form constitute forward-looking statements. The use of any of the words “anticipate”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “believe” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form.

In particular, this Annual Information Form may contain forward-looking statements and information pertaining to the following:

- the performance characteristics of the Corporation’s oil and natural gas properties;
- oil and natural gas production levels, and expectations of future production rates, volumes and product mixes;
- the size of the oil and natural gas reserves of the Corporation and anticipated future cash flows from such reserves;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- the Corporation’s dividend policy and the amount of timing of dividends;
- treatment under governmental regulatory regimes and tax and royalty laws;
- criteria and considerations in participations and acquisitions;
- tax horizon;
- timing of development of undeveloped reserves;
- estimated abandonment and reclamation costs and the timing thereof;
- expected land expiries and plans with respect thereto;
- plans to implement enhanced recovery; and
- capital expenditure programs, the allocation of such capital and the timing thereof.

With respect to forward looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding:

- oil and natural gas production levels and the timing of new wells coming on-stream;
- the success of the Corporation’s operations and exploration and development activities;
- the size of Surge’s oil, natural gas and NGL reserves and the recoverability of its reserves;
- prevailing weather conditions, commodity prices and exchange rates;
- the availability of labour, services and drilling equipment;
- the availability of capital to fund planned expenditures;
- timing and amount of capital expenditures;
- timing of production curtailments;
- future operating costs and future cash flow;
- the Corporation’s future debt levels;
- general economic and financial market conditions;
- the Corporation’s ability to market production of oil and natural gas successfully to customers;
- the applicability of technologies for recovery and production of the Corporation’s reserves;
- the success, nature and timing of water flood activities;
- the ability of the Corporation to secure necessary capital, personnel, equipment and services; and
- government regulation in the areas of taxation, royalty rates and environmental protection.

The actual results, performance or achievements of the Corporation may differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves and production levels;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- failure to obtain industry partner or other third party consents and approvals, when required;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- fluctuations in the cost of borrowing;
- the marketability of production and demand of Surge's products;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions, dispositions and exploration and development programs;
- geological, technical, drilling, completion and processing problems;
- results of water flood responses;
- the outcome of litigation or regulatory proceedings brought against the Corporation or other disputes involving the Corporation;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry;
- cyber-security issues;
- failure to realize the anticipated benefits of acquisitions and dispositions; and
- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. The Corporation does not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

SURGE ENERGY INC.

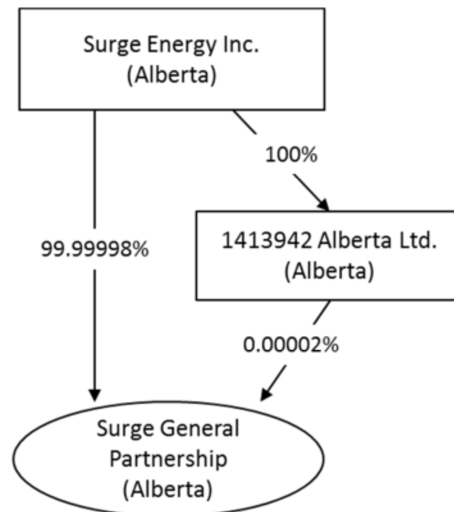
Corporate Structure

Surge was incorporated on January 26, 1998 under the ABCA as "Zapata Capital Inc." On June 18, 1999, the Corporation acquired all of the issued and outstanding shares of 744997 Alberta Ltd. and amalgamated with 744997 Alberta Ltd. under the name "Zapata Energy Corporation". On June 25, 2010, the Corporation changed its name to "Surge Energy Inc." On December 31, 2010, the Corporation amalgamated with its wholly-owned subsidiary, Breaker Resources Ltd. On December 31, 2012, the Corporation amalgamated with is wholly-owned subsidiary, Surge Oil Inc. On December 31, 2013, the Corporation amalgamated with its wholly-owned subsidiaries, Flagstone Energy Inc. and 1779275 Alberta Ltd. On December 31, 2014, the Corporation amalgamated with its wholly-owned subsidiary, Longview Oil Corp. On December 31, 2018, the Corporation amalgamated with its wholly-owned subsidiary, Mount Bastion Oil & Gas Corp.

The head office of the Corporation is located at 2100, 635 – 8th Avenue S.W., Calgary, Alberta T2P 3M3. The registered office of the Corporation is located at Suite 4000, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

Intercorporate Relationships

The Corporation currently has one wholly-owned subsidiary, 1413942 Alberta Ltd. The Corporation and 1413942 Alberta Ltd. are the partners of Surge General Partnership. The corporate structure of the Corporation and its subsidiaries is as set forth in the diagram below:



DEVELOPMENT OF THE BUSINESS

General

The Corporation is an independent, Calgary, Alberta-based oil and gas company operating primarily in Alberta and Saskatchewan. The Common Shares are listed on the TSX under the symbol "SGY" and the Debentures are listed on the TSX under the symbol "SGY.DB".

Three Year History

Significant developments of the Corporation over the last three completed financial years are as set forth below:

Year ended December 31, 2016

On March 24, 2016, Surge completed the sale of certain facilities at its Valhalla light oil and natural gas assets in NW Alberta for $15 million. The Corporation will maintain control of the Valhalla facilities as operator, and will pay the purchaser an annual tariff for the life of the agreement. Surge will also retain all third-party processing revenues generated from the facilities. On March 31, 2016, Surge also closed the sale of the Corporation's non-core Sunset property in Northern Alberta for proceeds of $28 million.

In the fourth quarter of 2016, Surge purchased Montney reserves and production associated with 3 sections of 100 percent working interest lands within the Valhalla Montney B Oil pool. The purchase also included a 1.97 percent working interest ownership in a nearby sour gas processing facility.

Year ended December 31, 2017

In 2017, Surge completed two acquisitions of crude oil producing assets in its core Sparky area of Central Alberta. On April 12, 2017, Surge completed the acquisition of assets producing 745 boe/d (97 percent crude oil) for a purchase price of $37 million, paid in cash. On September 8, 2017, Surge acquired assets producing 780 boe/d (95 percent crude oil) for a purchase price of $37.2 million, paid in cash.

Year ended December 31, 2018

On January 4, 2018, Surge completed the sale of certain non-core assets in Central Alberta for proceeds of $6.7 million.

On May 31, 2018, Surge completed an acquisition of crude oil producing assets in its core Sparky area of Central Alberta for a purchase price of $27.9 million.

On July 18, 2018, Surge completed an acquisition of crude oil producing assets in its core Valhalla area of Northern Alberta for a purchase price of $6.2 million.

On October 25, 2018, Surge closed its acquisition of Mount Bastion Oil & Gas Corp. ("**Mount Bastion**") pursuant to an arrangement under the provisions of the ABCA. See "*Development of the Business – Significant Acquisitions*".

Significant Acquisitions

On October 25, 2018, Surge acquired all the issued and outstanding shares of Mount Bastion for total consideration of approximately $299 million, comprised of approximately $145 million cash and approximately 75.4 million common shares of Surge. Surge filed a Form 51-102F4 - *Business Acquisition Report* dated October 31, 2018, in respect of this acquisition.

DESCRIPTION OF THE BUSINESS

Overview

The Corporation is a moderate growth, dividend paying oil and gas exploration, development and production company. Surge holds focused and operated light and medium gravity crude oil properties, primarily in Alberta and Saskatchewan, characterized by large oil in place crude oil reservoirs with low recovery factors. The Corporation has a significant inventory of low risk development drilling locations, including several successful water flood projects.

Corporate Strategy

The Corporation is building a moderate growth, dividend paying oil and gas company with focused, operated light and medium gravity crude oil assets. The Corporation focuses on assets with the following criteria: large oil in place with low recovery factors; available infrastructure; high working interest; operatorship; all-season access and drilling inventory; water flood opportunities; and other upside that provides a definable high rate of return.

Management believes in controlling the timing and costs of the Corporation's projects wherever possible. Accordingly, the Corporation seeks to become the operator of its properties. Further, to minimize competition within its geographic areas of interest, the Corporation strives to maximize its working interest ownership in its properties where reasonably possible.

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria: risk capital to secure or evaluate the opportunity; the potential return on the project, if successful; the likelihood of success; and risked return versus cost of capital.

In general, the Corporation pursues a portfolio approach in developing a large number of opportunities with a balance of risk profiles in an attempt to generate sustainable levels of growth. The Board of Directors of the Corporation may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon the Board's consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

In addition, the management team of the Corporation, as described below under "*Directors and Officers*", is continually assessing the assets and operations of the Corporation, including its existing land base, facilities, reserves, prospects and personnel.

Competition

The oil and natural gas industry is competitive in all its phases. The Corporation competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include resource companies which have greater financial resources, staff and facilities than those of the Corporation. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Corporation believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Cyclical and Seasonal Nature of Industry

Surge's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated dramatically during recent years and are determined by a number of factors, including global and local supply and demand factors, and including weather and general economic conditions, as well as conditions in other oil and natural gas producing and consuming regions. Surge attempts to mitigate such price risk through closely monitoring commodity markets and establishing disciplined hedging programs.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain.

Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation. Demand for natural gas typically rises during cold winter months and hot summer months.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. See below under the headings "*Industry Conditions - Environmental Regulation*" and "*Risk Factors – Environmental Concerns*".

The Corporation is obligated to abandon, retire and reclaim wells and wellsites in compliance with applicable environmental laws and regulations. As of December 31, 2018, the Corporation has recorded an asset retirement obligation of $229 million. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of fifty years, with the majority of the expenditures being incurred from years 2023 to 2066. Other than asset retirement obligations and ordinary course operational expenditures necessary to ensure environmental compliance, the Corporation is not aware of any environmental protection requirement that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its area of operations.

Marketing

Surge's crude oil and natural gas production are sold primarily through marketing companies at current market prices. See also "*Interest of Management and Others in Material Transactions*".

The Corporation also has a hedging policy as described under "*Statement of Reserves Data – Other Oil and Gas Information – Forward Contracts*". For details of the Corporation's forward contracts in place as at December 31, 2018, see the Corporation's audited annual financial statements for the year ended December 31, 2018, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Fixed Price Hedging*".

Personnel

As at December 31, 2018, the Corporation had 68 head office employees and 4 field employees.

Health, Safety and Environmental

Management, employees and contractors are responsible and accountable for the overall health, safety and environmental program. Surge operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

Surge maintains a safe and environmentally responsible work place and provides training, equipment and procedures to all individuals in adhering to its policies. It also solicits and takes into consideration input from neighbors, communities and other stakeholders in regard to protecting people and the environment.

PRINCIPAL PRODUCING PROPERTIES

The Corporation's principal oil and natural gas producing properties are located in Alberta and Saskatchewan and are focused across five core areas: Greater Sawn, Valhalla, Sparky, Shaunavon and Minors. A description of those properties, as at December 31, 2018, is provided below.

Greater Sawn

As at December 31, 2018, the Corporation's principal properties in the Greater Sawn area included Sawn Lake, Otter, Red Earth (which collectively comprise the Greater Sawn Lake assets) and Nipisi. At Greater Sawn, Surge held an average working interest of approximately 84 percent in approximately 96,278 gross (81,256 net) developed acres and an average working interest of approximately 93 percent in approximately 196,445 gross (183,376 net) undeveloped acres. As at December 31, 2018, the Corporation held interests in 340 gross (271 net) oil wells producing from formations including, but not limited to, Slave Point, Granite Wash and Gilwood. In addition, the Corporation operates multiple oil batteries providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2018 production in Greater Sawn was approximately 4,100 boe/d (98 percent oil and NGLs).

Greater Sawn Lake

The Greater Sawn Lake assets are comprised of three main fields (Sawn Lake, Otter and Red Earth) near Red Earth Creek in Northern Alberta. Production from this property is primarily 40° API light oil from the Slave Point and Granite Wash formations. The majority of the new development is focused on the Slave Point formation. The majority of these pools are currently on primary production with horizontal Slave Point waterflood being implemented in Sawn Lake. These assets were acquired on October 25, 2018, with the corporate acquisition of Mount Bastion.

In 2018, the Corporation drilled 2 gross (2.0 net) Slave Point horizontal, multi-frac oil wells at Sawn Lake.

Nipisi

The Nipisi property is located approximately 50 kilometres north of the town of Slave Lake, in northwestern Alberta. Light oil production is from the Slave Point and Gilwood formations. The Slave Point production is from horizontal, multi-frac wells and the Gilwood production is from vertical wells.

Valhalla

As at December 31, 2018, the Corporation's principal property in the Valhalla area is the Valhalla/Wembley property. At Valhalla, Surge held an average working interest of approximately 70 percent in approximately 44,242 gross (31,104 net) developed acres and an average working interest of approximately 68 percent in approximately 35,442 gross (24,056 net) undeveloped acres. As at December 31, 2018, the Corporation held interests in 149 gross (111 net) oil wells and 21 gross (10 net) gas wells producing from formations including, but not limited to, Doig, Doe Creek, Montney, and Charlie Lake. In addition, the Corporation operates multiple oil batteries providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2018 production in Valhalla was approximately 5,600 boe/d (54 percent oil and NGLs).

Valhalla/Wembley

The Valhalla/Wembley property is located in northwestern Alberta, approximately 40 kilometres northwest of Grand Prairie. The majority of production from this property was from the horizontal oil wells producing from an extensive tight sand, with up to 40 metres of gross light oil pay in the Triassic Doig formation. Additional production is from a shallow, waterflooded, Doe Creek light oil pool.

In 2018, the Corporation drilled 4 gross (4.0 net) Doig horizontal, multi-frac oil wells at Valhalla and 1 gross (1.0 net) Charlie Lake horizontal.

Sparky

As at December 31, 2018, Surge's principal properties in the Sparky area included the Sparky assets and the Lloyd/Cummings zone waterflood at Silver. At Sparky, Surge held an average working interest of

approximately 88 percent in approximately 67,759 gross (59,321 net) developed acres and an average working interest of approximately 95 percent in approximately 58,602 gross (55,667 net) undeveloped acres. As at December 31, 2018, the Corporation held interests in 502 gross (405 net) oil wells and 23 gross (20 net) gas wells producing from formations including, but not limited to, Sparky, Lloydminster, and Cummings. In addition, the Corporation operates multiple oil batteries, providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2018 production in Sparky was approximately 7,400 boe/d (91 percent oil and NGLs).

Sparky

The Sparky assets are comprised of six main fields spread between Provost and Wainwright in eastern Alberta and western Saskatchewan. Eye Hill, Provost and Betty Lake are early stage primary development properties, while Wainwright, Macklin, Lakeview, and East Sounding are more mature, mostly developed waterflood assets. Production from the Sparky assets is primarily crude oil (89 percent oil and NGLs) ranging from 23° to 28° degrees API.

In 2018, the Corporation drilled 25 gross (24.6 net) horizontal, multi-frac, Sparky oil wells and converted two more horizontal wells to injection at Eyehill.

Silver

The Silver Lake property is located west of Provost in eastern Alberta. Production from this property is primarily 24° API Crude oil from the Lloydminster and Cummings formations. The field has been developed by a mixture of horizontal and vertical wells and is extensively under waterflood.

Shaunavon

The Shaunavon properties are primarily located approximately 100 kilometres southwest of Swift Current, Saskatchewan and 140 kilometres east of the Alberta border. As at December 31, 2018, these operated properties included an average working interest of approximately 100 percent in approximately 23,129 gross (23,129 net) developed acres and an average working interest of approximately 100 percent in 23,129 gross (23,129 net) undeveloped acres. As at December 31, 2018, the Corporation held interests in 188 gross (188 net) oil wells producing from the Upper and Lower Shaunavon formations, among others. The Corporation's production from this property is weighted 100 percent to medium crude oil (21-26° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2018 production was approximately 2,600 boe/d (100 percent oil).

In 2018, the Corporation continued the development and delineation of the extensive Upper and Lower Shaunavon formations, with the drilling of 14 gross (14.0 net) horizontal, multi-frac, oil wells. The Corporation also expanded a horizontal, waterflood pilot in the Upper Shaunavon, with the conversion of 1 additional producing wells to water injection.

Minors

As at December 31, 2018, the Corporation's principal properties in the Minors area included Nevis, Westerose, Edmonton and other minor areas. At Minors, Surge held an average working interest of approximately 73 percent in approximately 40,911 gross (29,932 net) developed acres and an average working interest of approximately 60 percent in approximately 7,164 gross (4,293 net) undeveloped acres. As at December 31, 2018, the Corporation held interests in 114 gross (92 net) oil wells and 27 gross (18 net) gas wells producing from formations including, but not limited to, Wabamun, Banff and Rock Creek. This area's fourth quarter 2018 production was approximately 1,300 boe/d (67 percent oil and NGLs).

STATEMENT OF RESERVES DATA

In accordance with NI 51-101, Sproule prepared the Reserves Report based on its evaluation of the oil, NGL and natural gas reserves attributable to the properties of the Corporation as at December 31, 2018. The Reserves Report is dated February 27, 2019.

The tables below are a combined summary of the oil, NGL and natural gas reserves attributable to the properties of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Reserves Report based on forecast price and cost assumptions. The tables summarize the data contained in the Reserves Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves evaluated. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The Reserves Report is based on certain factual data supplied by the Corporation and Sproule's opinions of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Gross Reserves					Net Reserves				
	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)
Proved										
Developed Producing	23,466.5	12,653.3	1,390.8	34,766.0	603.0	20,139.0	11,610.5	1,033.6	32,051.0	531.0
Developed Non-Producing	695.9	898.3	36.4	989.0	-	603.9	854.9	26.9	919.0	-
Undeveloped	20,155.4	7,799.1	1,381.9	34,855.0	1,318.0	17,153.8	7,314.8	1,148.1	32,194.0	1,241.5
Total Proved	44,317.9	21,350.7	2,809.2	70,610.0	1,921.0	37,896.7	19,780.2	2,208.6	65,164.0	1,772.5
Probable	24,792.7	10,371.5	1,227.3	33,590.0	521.0	19,895.6	9,446.6	945.8	30,687.0	488.0
Total Proved plus Probable	69,110.6	31,722.1	4,036.5	104,200.0	2,442.0	57,792.3	29,226.9	3,154.4	95,851.0	2,260.5

Net Present Value of Future Net Revenue – Forecast Prices and Costs

	Before Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	566,889	815,232	740,580	656,039	587,143
Developed Non-Producing	64,965	48,929	39,257	32,794	28,169
Undeveloped	1,049,395	738,006	537,741	403,790	310,631
Total Proved	1,681,249	1,602,168	1,317,578	1,092,623	925,943
Probable	1,698,557	1,059,801	735,975	548,170	428,413
Total Proved plus Probable	3,379,806	2,661,969	2,053,553	1,640,793	1,354,356

($M)	After Future Income Tax Expenses and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed Producing	566,889	815,232	740,580	656,039	587,143
Developed Non-Producing	64,965	48,929	39,257	32,794	28,169
Undeveloped	816,585	576,024	420,551	316,277	243,561
Total Proved	1,448,439	1,440,186	1,200,388	1,005,110	858,872
Probable	1,275,349	780,859	537,395	398,762	311,418
Total Proved plus Probable	2,723,788	2,221,044	1,737,782	1,403,872	1,170,290

	Unit Value before Income Tax Discounted at 10%/year ($/boe)
Proved	
Developed Producing	19.38
Developed Non-Producing	23.95
Undeveloped	17.24
Total Proved	18.55
Probable	20.74
Total Proved plus Probable	19.28

Additional Information Concerning Future Net Revenue – Forecast Prices and Costs (Undiscounted)

(Undiscounted) ($M)	Revenue	Royalties	Operating Costs	Develop-ment Costs	Abandon-ment and Other Costs	Future net revenue before income taxes	Future income taxes	Future net revenue after income taxes
Total Proved	5,822,799	688,829	2,180,201	644,166	628,354	1,681,249	232,810	1,448,439
Total Proved plus Probable	9,317,589	1,238,728	3,201,069	853,621	644,366	3,379,806	656,019	2,723,788

Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and Discounted at 10% per year ($M)	Per Unit Future Net Revenue Before Income Taxes and Discounted at 10%[3] per year ($/boe)
Proved		
Light and Medium Crude Oil[1]	910,482	18.45
Heavy Crude Oil[1]	398,380	19.42
Conventional Natural Gas[2]	6,044	8.13
Coalbed Methane[2]	2,672	6.21
Proved plus Probable		
Light and Medium Crude Oil[1]	1,447,905	19.39
Heavy Crude Oil[1]	594,801	9.63
Conventional Natural Gas[2]	7,525	7.50
Coalbed Methane[2]	3,322	6.05

Notes:
1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas from oil wells.
3. Based on net reserves volumes.

Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following pricing and inflation rate assumptions as of December 31, 2018 in its evaluation in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2018 are also reflected in the table below.

	Medium and Light Crude Oil		Natural Gas	NGL					
Year	**Canadian Light Sweet Crude 40 API ($/bbl)**	**Western Canada Select 20.5 API ($/bbl)**	**Alberta AECO Gas Price ($/MMBtu)**	**Edmonton Pentanes plus ($/bbl)**	**Edmonton Butane ($/bbl)**	**Edmonton Propane ($/bbl)**	**Operating Cost Inflation rates (%/Yr)**	**Capital Cost Inflation rates (%/Yr)**	**Exchange rate ($US/$Cdn)**
2018 (Surge Actual)	68.49	52.34	1.53	79.31	33.65	27.00	2.5%	4.2%	0.77
2019	75.27	59.47	1.95	75.32	40.91	30.27	0.0%	0.0%	0.77
2020	77.89	62.31	2.44	80.00	50.25	34.51	2.0%	2.0%	0.80
2021	82.25	67.45	3.00	83.75	56.88	38.15	2.0%	2.0%	0.80
2022	84.79	69.53	3.21	85.50	58.01	39.64	2.0%	2.0%	0.80
2023	87.39	71.66	3.30	87.29	59.17	40.62	2.0%	2.0%	0.80
2024	89.14	73.10	3.39	89.11	60.36	41.62	2.0%	2.0%	0.80
2025	90.92	74.56	3.49	90.96	61.56	42.64	2.0%	2.0%	0.80
2026	92.74	76.05	3.58	92.86	62.79	43.68	2.0%	2.0%	0.80
2027	94.60	77.57	3.68	94.79	64.05	44.75	2.0%	2.0%	0.80
2028	96.49	79.12	3.78	96.76	65.33	45.83	2.0%	2.0%	0.80
2029	98.42	80.70	3.88	98.77	66.64	46.94	2.0%	2.0%	0.80

Escalated thereafter at a rate of +1.5% per annum.

Reconciliation of Changes in Reserves

The following table sets forth a combined reconciliation of the Corporation's gross reserves as at December 31, 2018, derived from the Reserves Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2018.

	Light and Medium Crude Oil (Mbbls)	**Heavy Crude Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Conventional Natural Gas (MMcf)**	**Coalbed Methane (MMcf)**	**Boe (Mboe)**
Proved						
Balance at December 31, 2017	26,720	20,228	3,057	63,938	2,814	61,130
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery[1]	1,061	1,179	61	3,175	-	2,831
Infill Drilling[1]	1,241	1,066	71	2,316	-	2,764
Technical Revisions[2]	2,315	(1,033)	(407)	8,518	(768)	2,168
Acquisitions[3]	16,723	2,037	325	4,355	-	19,811
Dispositions	(464)	(559)	(13)	(3,121)	-	(1,555)
Economic Factors[4]	73	186	(58)	(1,134)	(22)	9
Production	(3,353)	(1,754)	(227)	(7,438)	(103)	(6,591)
Balance at December 31, 2018	44,318	21,351	2,810	70,610	1,921	80,566

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
Probable						
Balance at December 31, 2017	16,210	10,747	1,483	33,233	639	34,086
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery[(1)]	1,521	927	70	3,218	-	3,054
Infill Drilling[(1)]	1,276	461	51	1,800	-	2,088
Technical Revisions[(2)]	(1,099)	(2,518)	(492)	(4,100)	(102)	(4,810)
Acquisitions[(3)]	7,204	1,111	141	1,999	-	8,789
Dispositions	(414)	(264)	(16)	(2,153)	-	(1,053)
Economic Factors[(4)]	96	(91)	(11)	(407)	(16)	(77)
Production	-	-	-	1	-	0
Balance at December 31, 2018	24,793	10,372	1,227	33,591	521	42,077

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
Proved plus Probable						
Balance at December 31, 2017	42,930	30,975	4,540	97,171	3,453	95,216
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery[(1)]	2,582	2,106	132	6,393	-	5,885
Infill Drilling[(1)]	2,518	1,526	123	4,116	-	4,852
Technical Revisions[(2)]	1,216	(3,551)	(899)	4,419	(870)	(2,642)
Acquisitions[(3)]	23,927	3,148	465	6,354	-	28,599
Dispositions	(878)	(823)	(28)	(5,274)	-	(2,608)
Economic Factors[(4)]	169	95	(69)	(1,541)	(38)	(68)
Production	(3,353)	(1,754)	(227)	(7,437)	(103)	(6,591)
Balance at December 31, 2018	69,111	31,722	4,037	104,201	2,442	122,643

Notes:

1. Includes the expansion or increased recovery factor for existing reservoirs as a result of additional step-out drilling, infill drilling or enhanced oil recovery activities.
2. Changes in booked reserves from previously estimated levels. In 2018, a majority of the negative revisions were due to reductions in expected recovery from wells in the Shaunavon field as well as reduction of NGL yields at Valhalla.
3. Changes in reserves due to the acquisition of producing properties. Includes reserves estimated at December 31, 2018, plus any production from the asset attributable to the company in the prior year. A majority of the changes were due to the acquisition of Mount Bastion Oil and Gas Corp.
4. Changes in reserves exclusively due to changes in product pricing.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)
Proved				
2016	2,967.7	790.6	272.9	6,427.0
2017	1,928.5	2,447.2	101.0	2,482.0
2018	7,495.4	2,242.0	209.5	5,167.0

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)
Probable				
2016	1,915.1	1,402.2	183.7	4,177.0
2017	2,067.5	1,323.1	203.9	4,739.0
2018	5,787.5	1,777.3	170.2	5,051.0

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Corporation currently plans to pursue the development of its proven and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, the Corporation may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the combined total development costs deducted in the estimation in the Reserves Report of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

	Forecast Prices and Costs	
	Proved Reserves ($M)	Proved plus Probable Reserves ($M)
2019	113,198	127,004
2020	155,166	202,338
2021	166,415	192,490
2022	109,311	165,037
2023	63,599	107,191
Remaining Years	36,478	59,561
Total Undiscounted	644,167	853,621

The Corporation has four sources of funding available to finance its capital expenditure programs: internally generated cash flow from operations, funds raised from the sale of non-core assets, debt financing when appropriate and new issues of Common Shares, if available on favourable terms. The Corporation expects to fund the above future development costs primarily through internally generated cash flow, funds raised from the sale of non-core assets and debt. There can be no guarantee that the Board of Directors will allocate funding to develop all of the reserves attributed in the Reserve Reports or either of them. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

Other Oil and Gas Information

Oil and Gas Wells

The following table sets forth the number and status of the Corporation's wells effective December 31, 2018.

	Producing								Non-Producing							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp		Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,249	989	118	58	9	6	349	260	2,113	1,698	467	345	2	2	240	200
Saskatchewan	220	213	76	5	-	-	26	24	66	46	17	8	-	-	6	4
Total	1,469	1,202	194	63	9	6	375	284	2,179	1,744	484	353	2	2	246	204

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2018, the gross and net acres of unproved properties in which the Corporation has an interest and also the number of net acres for which the Corporation's rights to explore, develop or exploit will, absent further action, expire within one year.

	Gross Undeveloped Acres	Net Undeveloped Acres	Net Undeveloped Acres Expiring within One Year
Alberta	327,734	277,609	6,000
Saskatchewan	21,398	19,463	3,120
Total	349,132	297,072	9,120

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation typically estimates well abandonment costs area by area. Such costs are included in the Reserves Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the Reserves Report for 1,413 net wells under the proved reserves category is $628 million undiscounted ($61.2 million discounted at 10 percent), of which a total of $15.7 million is estimated to be incurred in 2019, 2020 and 2021. This estimate includes expected reclamation costs for surface leases which have existing wells with economic developed reserves assigned or future development drilling locations. The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Subject to pending changes in applicable regulations regarding the abandonment and reclamation, ongoing environmental obligations are expected to be funded out of cash flow.

Forward Contracts

Surge is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by Surge to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. Surge is exposed to losses in the event of default by the counterparties to these derivative instruments. Surge manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties.

Based largely upon the Keystone pipeline outage in late 2017, as well as pipeline egress constraints in late 2018, Western Canadian Select ("**WCS**") crude oil differentials widened beyond the three year historical average of US $13.10 per bbl (i.e. the average for 2015 through 2017). Surge proactively mitigates the impact of crude oil differentials continuously through numerous light oil blending initiatives in its Sparky core area. Furthermore, the Corporation has 2,300 bbl per day of WCS differentials hedged for the first half of 2019 with a cap of US $19 per barrel.

For details of the Corporation's forward contracts in place as at December 31, 2018, see the Corporation's audited annual financial statements for the year ended December 31, 2018, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Fixed Price Hedging*".

Tax Horizon

Based on planned capital expenditures and the forecast commodity pricing employed in the Reserves Report, the Corporation estimates that it will not be required to pay current income taxes before 2023.

Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2018.

	Property Acquisition Costs				
	Proved Properties	**Unproved Properties**	**Property Dispositions**	**Exploration Costs**	**Development Costs**
Total ($M)	334,821	-	(7,056)	-	120,552

Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by the Corporation based on rig release date during the year ended December 31, 2018.

	Exploration Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Crude Oil	-	-	46.00	45.56
Heavy Crude Oil	-	-	-	-
Conventional Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total	-	-	46.00	45.56

Planned Capital Expenditures

The Corporation has announced a planned capital expenditure budget of approximately $135 million for 2019.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Reserves Report for 2018 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coalbed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Boe (boe/d)	%
Proved							
Greater Sawn	4,909	181	463	-	93	5,260	23
Valhalla	3,109	-	15,377	-	466	6,138	27
Sparky	4,164	2,477	3,142	-	75	7,239	31
Shaunavon	-	3,170	-	-	-	3,170	14
Minors	516	93	2,399	258	165	1,217	5
Total Proved	12,699	5,920	21,381	258	799	23,024	100%
Proved Plus Probable							
Greater Sawn	5,536	184	500	-	109	5,912	23
Valhalla	3,426	-	17,141	-	519	6,802	27
Sparky	4,644	2,699	3,615	-	82	8,029	31
Shaunavon	-	3,526	-	-	-	3,526	14
Minors	527	95	2,485	263	169	1,249	5
Total Proved Plus Probable	14,133	6,505	23,741	263	880	25,518	100%

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2018, certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the Corporation.

Average Daily Production Volume

	Three Months Ended			
	Mar 31, 2018	**Jun 30, 2018**	**Sep 30, 2018**	**Dec 31, 2018**
Conventional Natural Gas (Mcf/d)	17,633	18,688	22,363	22,166
Light and Medium Crude Oil (bbls/d)	12,446	13,343	13,560	16,578
NGL (bbls/d)	560	556	669	703
Coalbed Methane (Mcf/d)	495	350	434	432
Total (boe/d)	16,027	17,072	18,029	21,047

Prices Received, Royalties Paid, Production Costs and Netback – Crude Oil

	Three Months Ended			
($ per Bbl)	**Mar 31, 2018**	**Jun 30, 2018**	**Sep 30, 2018**	**Dec 31, 2018**
Prices Received	47.10	55.92	54.81	29.91
Royalties Paid	(6.19)	(8.36)	(8.33)	(3.82)
Production Costs	(13.93)	(13.91)	(13.53)	(1.48)
Transportation Costs	(1.26)	(1.62)	(1.55)	(1.52)
Netback[(1)]	25.72	32.03	31.40	23.09

Note:

1. Including solution gas and associated natural gas liquids revenue.

Prices Received, Royalties Paid, Production Costs and Netback – Conventional Natural Gas

($ per Mcf)	Three Months Ended			
	Mar 31, 2018	Jun 30, 2018	Sep 30, 2018	Dec 31, 2018
Prices Received	1.45	0.81	0.49	0.64
Royalties Paid	(0.04)	0.03	0.04	(0.23)
Production Costs	(4.04)	(1.52)	(4.97)	(85.29)
Transportation Costs	-	(0.01)	(0.00)	(0.05)
Netback	(2.63)	(0.69)	(4.45)	(84.93)

Prices Received, Royalties Paid, Production Costs and Netback – Combined

($ per boe)	Three Months Ended			
	Mar 31, 2018	Jun 30, 2018	Sep 30, 2018	Dec 31, 2018
Prices Received	47.34	56.06	54.89	30.02
Royalties Paid	(6.20)	(8.36)	(8.32)	(3.86)
Production Costs	(14.60)	(14.16)	(14.36)	(15.70)
Transportation Costs	(1.26)	(1.62)	(1.55)	(1.53)
Netback[(1)]	25.28	31.92	30.66	8.93

Note:

1. Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

Production Volume by Field

The following table indicates the average daily net production from the Corporation's important fields for the year ended December 31, 2018.

Field	Light and Medium Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Coalbed Methane (Mcf/d)	Boe (boe/d)	%
Greater Sawn	1,450	101	22	-	1,489	8%
Valhalla	3,310	13,477	330	-	5,886	33%
Sparky	6,151	3,402	68	-	6,786	38%
Shaunavon	2,421	5	-	-	2,422	13%
Minors	660	3,245	203	428	1,475	8%
Sold Properties	1	-	-	-	1	0%
Total	13,992	20,230	623	428	18,058	100%

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series.

Common Shares

The holders of Common Shares are entitled to: (i) one vote for each Common Share held at all meetings of shareholders of the Corporation other than meetings of the holders of any class or series of shares meeting as a class or series; (ii) receive any dividends declared by the Corporation on the Common Shares; and (iii) subject to the rights of shares ranking prior to the Common Shares, to receive the remaining property of the Corporation on dissolution, after the payment of all liabilities.

Preferred Shares

Preferred shares may be issued in one or more series. The Board of Directors is authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series. Preferred shares of the Corporation are entitled to a priority over the Common Shares with respect to the payment of dividends and the distribution of assets upon the liquidation, dissolution or winding-up of The Corporation.

Debentures

The Debentures are issued under and pursuant to the provisions of the indenture (the "**Indenture**") among Computershare Trust Company of Canada and Surge. The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Indenture which may be viewed under Surge's profile on SEDAR at www.sedar.com.

The Debentures will mature and be repayable on December 31, 2022 (the "**Maturity Date**") and will accrue interest at the rate of 5.75% per annum payable semi-annually in arrears on December 31 and June 30 of each year (each an "**Interest Payment Date**"), commencing on June 30, 2018 and computed on the basis of a 365-day year. The June 30, 2018 interest payment will represent accrued interest for the period from and including November 15, 2017 up to, but excluding, June 30, 2018. Interest on the Debentures will be payable in lawful money of Canada.

At the holder's option, the Debentures may be converted into Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earlier of the business day immediately preceding (i) the Maturity Date; and (ii) if called for redemption, the date fixed for redemption by the Corporation, at a conversion price of $2.75 per Common Share, subject to adjustment in certain events (the "**Conversion Price**"). This represents a conversion rate of approximately 363.6364 Common Shares for each $1,000 principal amount of Debentures, subject to certain anti-dilution provisions. Holders who convert their Debentures will receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to, but excluding, the date of conversion from, and including, the most recent Interest Payment Date. If a holder elects to convert its Debentures in connection with a change of control that occurs prior to the Maturity Date, the holder will be entitled to receive additional Common Shares as a make-whole premium on conversion in certain circumstances (as more fully described in the Indenture).

The Debentures are direct, subordinated, unsecured obligations of the Corporation, subordinated to any existing and future senior indebtedness of the Corporation and ranking equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation to the extent subordinated on the same terms.

The Debentures may not be redeemed by the Corporation prior to December 31, 2020 except in certain circumstances following a change of control. On and after December 31, 2020 and prior to December 31, 2021, the Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 30 days prior written notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption, provided that the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days prior to the date on which notice of redemption is provided is at least 125 percent of the Conversion Price. On or after December 31, 2021 and prior to the Maturity Date, the Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 40 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption.

The Debentures were listed and posted for trading on the TSX under the symbol "SGY.DB" at the open of markets on November 15, 2017.

DIVIDEND POLICY

The primary objective of the Corporation's dividend policy is to provide shareholders with relatively stable, predictable and sustainable monthly dividends.

The Credit Facility contains certain restrictions on Surge's ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, a corporation must be able to pay its liabilities as they become due and the realizable value of the assets of the corporation must be greater than the liabilities and the legal stated capital of its outstanding securities.

The following monthly cash dividends on Common Shares were declared for the periods indicated:

	Dividends per Common Share			
Month	**2019**	**2018**	**2017**	**2016**
January	0.008333	0.007917	0.006250	0.012500
February	0.008333	0.007917	0.007080	0.012500
March		0.007917	0.007080	0.012500
April		0.007917	0.007080	0.006250
May		0.007917	0.007917	0.006250
June		0.008333	0.007917	0.006250
July		0.008333	0.007917	0.006250
August		0.008333	0.007917	0.006250
September		0.008333	0.007917	0.006250
October		0.008333	0.007917	0.006250
November		0.008333	0.007917	0.006250
December		0.008333	0.007917	0.006250
Total	$0.016666	$0.097916	$0.090826	$0.093750

Unless otherwise specified, all dividends paid or to be paid are designated as "eligible dividends" under the *Income Tax Act* (Canada).

There can be no guarantee that the Corporation will maintain its dividend policy. The amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including the prevailing economic and competitive environment, results of operations, fluctuations in working capital, the price of oil and gas, the taxability of the Corporation, the Corporation's ability to raise capital, the amount of capital expenditures, the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends, applicable law and other factors. Additionally, the

agreement with respect to the Credit Facility contains certain restrictions on Surge's ability to pay dividends in certain circumstances. See "*Risk Factors – Dividends*".

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "SGY". The following table sets forth the market price ranges and the trading volumes for the Common Shares for the periods indicated, as reported by the TSX, for the year ended December 31, 2018.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
2018			
January	2.20	1.93	19,428,486
February	2.02	1.58	17,681,915
March	2.10	1.77	13,052,948
April	2.46	1.88	17,781,001
May	2.76	2.27	23,098,698
June	2.50	2.19	11,570,765
July	2.59	2.34	7,442,458
August	2.45	2.10	11,471,390
September	2.72	2.14	14,561,779
October	2.73	1.91	25,775,657
November	2.08	1.49	32,284,615
December	1.66	1.31	34,444,032

The Debentures are listed and posted for trading on the TSX under the trading symbol "SGY.DB". The following table sets forth the market price ranges and the trading volumes for the Debentures for the periods indicated, as reported by the TSX, for the year ended December 31, 2018.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
2018			
January	102.99	100.27	5,657,999
February	102.76	97.75	5,793,000
March	101.00	99.75	566,000
April	108.90	99.00	3,472,999
May	115.50	105.60	2,062,996
June	111.00	105.00	528,998
July	113.00	107.07	941,998
August	110.00	104.02	300,999
September	116.00	104.51	985,997
October	114.75	102.00	217,000
November	103.25	94.00	2,727,998
December	98.00	91.00	1,792,998

DIRECTORS AND OFFICERS

The name, municipality of residence, principal occupation for the prior five years and position with the Corporation of each of the directors and officers of the Corporation are as follows:

Name and Residence	Position	Principal Occupation During Previous Five Years
Paul Colborne Calgary, Alberta	President and Chief Executive Officer Director since April 13, 2010	President and CEO of the Corporation. He is also the President of StarValley Oil and Gas Ltd., a private, Calgary-based oil and gas company founded in November 2005. Mr. Colborne currently serves on the board of directors of Rising Star Resources Ltd., a private oil and gas company, and until its sale in February 2018, served on the board of directors of Red River Oil Inc., a private oil and gas company. In 1993, after nine years practicing securities, banking and oil and gas law, Mr. Colborne directed his focus to the oil and gas industry and founded an oil and gas company called Startech Energy Ltd., a publicly traded company, which grew to 15,000 boe/d. Eight years later in 2001, Startech was acquired by ARC Energy Trust for more than C$500 million. From September 2003 to January 2005, Mr. Colborne was the President and CEO of StarPoint Energy Trust, a 36,000 boe/d publicly traded energy trust. From 1996 to May 2013, Mr. Colborne was on the board of directors of Crescent Point Energy Corp., a 165,000 boe/d, publicly traded, dividend paying oil and gas company. Until its sale in July of 2009, Mr. Colborne served as Chairman of TriStar Oil & Gas Ltd. He was also previously a Director for Westfire Energy Ltd., Twin Butte Energy Ltd., Cequence Energy Ltd., and Chairman of Seaview Energy Ltd. Until its sale in December of 2009, he also served as a Director of Breaker Energy Ltd. Mr. Colborne was also Chairman and a Director of Mission Oil and Gas Inc. until its sale in February 2007. In May of 2014, Paul stepped down from the board of Legacy Oil + Gas. In June of 2014, Paul completed his term as Chairman of a private company called New Star Energy Ltd., and stepped down as a Director.
P. Daniel O'Neil[(3)(4)] Calgary, Alberta	Director since April 13, 2010	Independent businessperson since his retirement on May 8, 2013. Prior thereto, President and Chief Executive Officer of the Corporation since April 13, 2010. Prior thereto, President and Chief Executive Officer of Breaker Energy Ltd., a publicly traded oil and natural gas company, from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Mr. O'Neil was also a director of Cathedral Energy Services Ltd. Prior to its sale, Mr. O'Neil was also a director of Hyperion Exploration Corp.
Robert Leach[(1)(2)] Phoenix, Arizona	Director since April 13, 2010	Chief Executive Officer of Custom Truck Sales Ltd., a private company operating Kenworth truck dealerships in Saskatchewan and Manitoba, and Vice President of ReNue Properties Arizona Inc. Mr. Leach was formerly the Chairman of the board of directors of Breaker Energy Inc.
Keith Macdonald[(1)(3)(4)] Calgary, Alberta	Director since April 13, 2010	President of Bamako Investment Management Ltd., a private holding and financial consulting company since July 1994. Mr. Macdonald is currently Chairman, President and director of Drakkar Energy Ltd., a private oil and gas producer. He is also a director of Bellatrix Exploration Ltd., a company listed on the TSX and New York Stock Exchange. Mr. Macdonald was the Chief Executive Officer and a director of EFLO Energy Inc. from March 2011 to January 2015. Mr. Macdonald has served as an officer and director of a number of public and private energy companies.

Name and Residence	Position	Principal Occupation During Previous Five Years
Murray Smith[(1)(2)] Calgary, Alberta	Director since June 25, 2010	Chair of the Compensation Committee for the Corporation. President of Murray Smith and Associates. Mr. Smith also serves on the board of two private companies and Williams Companies Inc. (WMB.nyse), a Tulsa based midstream company. Prior thereto, Mr. Smith was an Official Representative of the Province of Alberta to the United States of America until 2007. Prior thereto, he was a member of the Legislative Assembly in the Province of Alberta serving in four different Cabinet portfolios – Energy, Gaming, Labour, and Economic Development from 1993 to 2005.
Daryl Gilbert[(2)(3)] Calgary, Alberta	Director since June 5, 2014	Chair of the Reserves Committee for the Corporation. Managing Director and Investment Committee member of JOG Capital Inc. since May 2008. Mr. Gilbert has also been an independent businessman and investor, and serves as a director for a number of public and private entities, since 2005. Mr. Gilbert has been active in the Western Canadian oil and natural gas sector for over 40 years, working in reserves evaluation with Gilbert Laustsen Jung Associates Ltd. (now GLJ Petroleum Consultants Ltd.) (“**GLJ**”), an engineering consulting firm, from 1979 to 2005. Mr. Gilbert served as President and Chief Executive Officer of GLJ from 1994 to 2005.
James Pasieka Calgary, Alberta	Director since April 13, 2010 Chairman of the Board since January 7, 2015	Partner of the national law firm McCarthy Tétrault LLP since September 2013. Prior thereto, partner of the national law firm Heenan Blaikie LLP since 2001. Mr. Pasieka has served as an officer and director of a number of public energy companies, and chairman of the board of several oil and gas companies.
Marion Burnyeat [(2)(4)] Calgary, Alberta	Director since July 16, 2018	Director, Calgary Academy and Headwater Learning Group since June 2018. Consultant with Inter Pipeline on mergers and acquisitions from April to June 2018. Vice President of Field Services at Westcoast Energy Inc. from January 2013 to March 2017. Prior thereto, Ms. Burnyeat served as Vice President of Midstream of Westcoast Energy Inc from May 2008 to January 2013. She served as Vice President Strategic Development and Stakeholder Relations at Westcoast Energy Inc from January 2007 to May 2008. Ms. Burnyeat has nearly thirty years in the energy sector primarily with Spectra Energy Corporation and its predecessor companies. She held increasingly responsible executive roles in leading Midstream business units, Strategic Development, Stakeholder Relations and Business Development. Ms. Burnyeat is currently taking the Directors Education Program (June 2019) with the Institute of Corporate Directors and holds a Bachelor of Commerce degree from the University of Alberta and a Masters of Business Administration degree from Edinburgh University. She serves on the board of Calgary Academy and Headwater Learning, has held positions on not for profit boards and is an active volunteer for several charitable organizations including Freestyle Alberta.
Allison Maher[(1)] Calgary, Alberta	Director since July 16, 2018	President, Director and Co-founder of Family Wealth Coach Planning Services since January 2009. Prior thereto, Ms. Maher worked at other financial-advisory and estate-planning companies such as Great-West Life (London Life) for almost two decades. Ms. Maher began her career at KPMG in the areas of Tax and Corporate Audit. Ms. Maher has her Certified Corporate Director, Chartered Professional Accountant and Certified Financial Planner designations. Ms. Maher received her Bachelor of Commerce degree, with Distinction, from the University of Calgary. Ms. Maher is an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not for profit boards.

Name and Residence	Position	Principal Occupation During Previous Five Years
Margaret Elekes Calgary, Alberta	Senior Vice-President, Land and Business Development	Senior Vice-President, Land and Business Development of the Corporation since August 2018. Prior thereto, Ms. Elekes was Vice-President, Land and Business Development of the Corporation from August 2016. Prior thereto, Vice-President, Land of the Corporation at Surge since April 2010. Prior thereto, Consulting Landman for Breaker Energy from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, US Land Manager for Upton Resources from December 1995 until its acquisition by StarPoint Energy in February 2004.
Murray Bye Calgary, Alberta	Chief Operating Officer	Chief Operating Officer of the Corporation since August 2018. Prior thereto, Mr. Bye was Vice President, Production of the Corporation from May 2013. Prior thereto, Mr. Bye was Asset Team Lead – West at Surge since June 2010. Prior to his role at Surge, Mr. Bye held a number of positions at EnCana Corporation between the years 2000 to 2010 including: Group Lead of Development, Exploitation Engineer, and Production Engineer. Mr. Bye received a Petroleum Engineering degree from Montana Tech.
Jared Ducs Calgary, Alberta	Vice President, Finance	Vice President, Finance of the Corporation since August 2018. Prior thereto, Mr. Ducs held increasingly responsible positions at Surge since April 2010 including Director of Corporate Development, Assistant Controller and Manager of Financial Reporting. Preceding his role at Surge, Mr. Ducs was a senior member of the Finance group at Breaker Energy Ltd., prior to its sale to NAL Oil & Gas Trust in 2009. Prior thereto, Mr. Ducs held the position of Senior Associate with Ernst & Young LLP. Mr. Ducs holds a Charted Accountant Designation and received his Bachelor of Management in Accounting and Finance from the University of Lethbridge.
Jim Stannard Calgary, Alberta	Executive Vice President	Executive Vice President of the Corporation since September 2018. Prior thereto, Mr. Stannard worked in a variety of engineering roles before completing 10 years in executive roles with Progress Energy from June 2002 to January 2013. Following the acquisition of Progress by PETRONAS Australia, Mr. Stannard stayed on in various executive roles from February 2013 to December 2016, including CEO and Managing Director of PETRONAS Australia. Mr. Stannard received a Petroleum Engineering degree from the University of Alberta.
Rod Monden Calgary, Alberta	Controller	Controller of the Corporation. Prior thereto, Mr. Monden held the position of Controller for Breaker Energy Ltd. from January 2008 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, he was the VP Finance and CFO of a private junior oil and gas company from September 2006 to October 2008. Prior thereto, Mr. Monden worked as Manager, Financial Reporting & Budgets at Burlington Resources Canada Ltd. from September 2002 to August 2006.

Notes:

1. Member of the Audit Committee.
2. Member of the Compensation, Nominating and Corporate Governance Committee of the Board.
3. Member of the Reserves Committee of the Board.
4. Member of the Environment, Health and Safety Committee of the Board.

As at March 12, 2019, the directors and executive officers of the Corporation, as a group, beneficially own, control or direct, directly or indirectly, 10,411, 205 Common Shares, representing approximately 3.4 percent of the outstanding Common Shares.

The terms of office of each of the directors of the Corporation will expire at the next annual general meeting of the shareholders of the Corporation.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set forth below, to the knowledge of management of the Corporation:

a) no director or executive officer of the Corporation is, or within the 10 years before the date of this AIF, has been, a director, chief executive officer or chief financial officer of any other issuer that: (i) was the subject of a cease trade or similar order or an order that denied the other issuer access to any exemptions under Canadian securities legislation that lasted for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation that lasted for a period of more than 30 consecutive days that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while the person was acting in the capacity as director, chief executive officer or chief financial officer;

b) no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person: (i) is, at the date of this AIF or has been within the 10 years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder; and

c) no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has: (i) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or (ii) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Mr. Gilbert was a director of Connacher Oil & Gas Limited ("**Connacher**") from October 2014 until February 2019. Mr. Gilbert initially joined Connacher's board of directors to assist in guiding Connacher through several financial restructurings. On May 17, 2016, Connacher applied for and was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the *Companies Creditor Arrangement Act* (Canada) ("**CCAA**"). On February 16, 2019 Connacher announced that it was proceeding to close on a credit bid transaction with its supporting lenders, which is expected to be consummated and will lead to a successful exit from CCAA in the first half of 2019. Mr. Gilbert resigned from Connacher shortly thereafter. Mr. Gilbert was also a director of LGX Oil + Gas Inc. ("**LGX**"), a public company with shares trading on the TSX Venture Exchange, which was placed into receivership in June 2016 and, in connection therewith, a receiver was appointed under the *Bankrutpcy and Insolvency Act* (Canada). Mr. Gilbert resigned as a director of LGX immediately following the appointment of the receiver. Cease trade orders in respect of LGX were issued shortly after the appointment of the receiver.

Mr. Macdonald was a director of Mountainview Energy Ltd. ("**Mountainview**"), a public company with shares trading on the TSX Venture Exchange, until March 15, 2017. A cease trade order in respect of Mountainview was issued by the Alberta Securities Commission on May 5, 2016 for failure to file its

annual continuous disclosure filings for the fiscal period ended December 31, 2015. As of the date hereof, the order remains in effect. Subsequently on October 14, 2016, a wholly-owned subsidiary of Mountainview filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code. A plan of reorganization was filed September 22, 2017 and amended October 16, 2017 to sell the company's oil and gas assets (and related abandonment/environmental obligations) in settlement of outstanding liabilities.

Mr. Pasieka was also a director of LGX. Mr. Pasieka resigned as a director of LGX in July 2015. LGX was placed into receivership nearly twelve months later in June 2016 and, in connection therewith, a receiver was appointed under the *Bankrutpcy and Insolvency Act* (Canada). Cease trade orders in respect of LGX were issued shortly after the appointment of the receiver.

Conflicts of Interest

As at the date hereof, the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation and a director or officer of the Corporation.

AUDIT COMMITTEE

Composition of the Audit Committee, Charter and Review of Services

The Audit Committee of the Board of Directors operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this AIF as Schedule "C".

The members of the Audit Committee of the Board of Directors are Keith Macdonald (Chair), Murray Smith, Robert Leach and Allison Maher. The Audit Committee charter requires all members of the Audit Committee to be "financially literate" and "independent" within the meaning of applicable securities laws. All members of the Audit Committee meet these requirements. The relevant education and experience of each Audit Committee member is outlined below:

Name	Independent	Financially Literate	Relevant Education and Experience
Keith Macdonald	✓	✓	Mr. Macdonald is currently the President of Bamako Investment Management Ltd., a private holding and financial consulting company, and Chairman, President and a director of Drakkar Energy Ltd., a private oil and gas producer. Mr. Macdonald is also a director of Bellatrix Exploration Ltd. Mr. Macdonald has served as an officer and director of a number of public and private energy companies. He has served as chair and/or a member of the audit committee of each of those companies, as well as several other public oil and gas companies for which he has been a director. Mr. Macdonald was also formerly a director of Breaker Energy Ltd. prior to its sale in 2009. From 1994 to January 1999, Mr. Macdonald was vice president of finance and a director of New Cache Petroleum Ltd. Mr. Macdonald founded New Cache Petroleum Ltd. in 1988 and was its president until a merger in 1994. Mr. Macdonald holds the Chartered Accountants designation, achieved in 1980, and a Bachelor of Commerce degree (Accounting and Finance Major) from University of Calgary in 1978.

Name	Independent	Financially Literate	Relevant Education and Experience
Murray Smith	✓	✓	President of Murray Smith and Associates and director of Williams Companies Inc. (WMB.nyse). Mr. Smith also serves on the board of two private companies. Prior thereto, Mr. Smith was an Official Representative of the Province of Alberta to the United States of America until 2007. Prior thereto, he was a member of the Legislative Assembly in the Province of Alberta serving in four different Cabinet portfolios – Energy, Gaming, Labour, and Economic Development from 1993 to 2005. From 1998-2004 Mr. Smith was a member of the Government of Alberta Treasury Board (responsible for the annual budget for Alberta) and a contributing member to Alberta's debt elimination in 2004. Mr. Smith has a degree in Economics from the University of Calgary (1971) and is a graduate of the London Business School Senior Executive Program (2000).
Robert Leach	✓	✓	Mr. Leach is currently the Vice President of ReNue Properties Arizona Inc., a Phoenix based real estate investment company. Mr. Leach was formerly the Chairman of the board of Breaker Energy Ltd. and holds a Bachelor of Commerce degree, majoring in accounting, from the University of Saskatchewan. Mr. Leach has experience reviewing and assessing financial statements from his tenure on the audit committee of Breaker, as a member of the Board of Surge, and through his years of experience at Custom Truck Sales Ltd. and International Fitness Holdings.
Allison Maher	✓	✓	Ms. Maher is currently the President and Director of her own advisory firm, Family Wealth Coach Planning Services. She is highly involved in matters related to succession planning, as well as family governance, estate and risk management. Ms. Maher began her career with KPMG in the areas of Tax and Corporate Audit. Ms. Maher is presently a member of the Chartered Professional Accountants of Alberta, as well as an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not for profit boards. Ms. Maher also holds Certified Corporate Director and Certified Financial Planner designations. Ms. Maher has been a member of the board of the Heritage Park Foundation since June 2014. Ms. Maher has been a trustee for the Cidel Donor Advised Fund since June 2014. From May 2011 to May 2017, she served as chairperson and advisory board member for the Alberta Business Family Institute (University of Alberta). Ms. Maher holds a Bachelor of Commerce degree, with Distinction, from the University of Calgary.

Pre-Approval of Policies and Procedures

The Audit Committee charter requires that any non-audit services by the Corporation's auditors must be pre-approved by the Audit Committee. The Audit Committee has passed a resolution providing the Chairman of the Audit Committee with delegated authority to approve the provision of non-audit services by the Corporation's auditors from time to time, provided that: (i) such services are provided pursuant to a written engagement letter setting out the services to be provided and the applicable fees; (ii) the provision of such services is otherwise in compliance with the Audit Committee's charter; (iii) such services could not be reasonably seen to result in the auditors performing any management function, auditing their own work or serving in an advocacy role on behalf of the Corporation; (iv) the fees for such services do not exceed $50,000 per engagement; and (v) the Chairman reports to the Committee at the next regularly scheduled meeting any approval of non-audit services made pursuant to the authority delegated under the resolution. The Audit Committee also pre-approves all audit services and the fees to be paid.

External Auditor Service Fees

KPMG LLP are the auditors of the Corporation. KPMG LLP have been the auditors of the Corporation since May 5, 2010.

The following table sets out the aggregate fees billed by KPMG LLP to the Corporation in each of the last two fiscal years.

Year	Audit Fees[(1)]	Audit-Related Fees	Tax Fees[(2)]	All Other Fees
2018	$235,000	$20,000	$86,000	$10,000
2017	$195,000	$64,000	$90,000	$60,000

Notes:

1. Audit fees consist of fees for the audit of annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. The services provided in this category included quarterly review fees.
2. Fees for tax compliance, tax advice and tax planning.

INDUSTRY CONDITIONS

Restrained Pipeline Capacity and Differential Volatility

Western Canada has seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline take-away capacity, leading to apportionment on the main lines and, in turn, backed-up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between WTI and Edmonton Par and the medium/heavy crude oil pricing differential between WTI and Cromer/WCS/Hardisty. Although pipeline expansions are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect the oil and natural gas industry in Western Canada and limit the ability to produce and to market production. In addition, the pro-rationing of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the National Energy Board of Canada ("**NEB**") and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced Bill C-69 to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made in the interim. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects.

Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects or their cancellation altogether.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Expansion from Hardisty, Alberta, to Superior, Wisconsin, has an expected in-service date in the latter half of 2019.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's indigenous consultations. The Federal Court of Appeal quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Federal Court of Appeal's direction, Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision, including the environmental effects of project-related marine shipping. On February 22, 2019, the NEB delivered an updated report to Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations, notwithstanding the fact that project-related marine shipping may have a significant adverse effect on the marine environment. Cabinet has three months to consider the NEB's report and, subject to a new round of indigenous consultation, decide whether it will approve or deny the pipeline expansion.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, preconstruction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed.

Finally, Bill C-48 continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGLs products from British Columbia's north coast. See "*Industry Conditions –Environmental Regulation – Federal*".

The Government of Alberta has also sought to alleviate these transportation constraints by pursuing different transportation modalities and creating new markets. On November 28, 2018, the Government of Alberta announced that Alberta had started negotiations for investment in new rail capacity to address the historically high price differential. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/d of crude oil out of the province. The Alberta Petroleum Marketing Commission will purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. The Government expects the first rail cars to be in service by July 2019 and believes this strategy will: (i) narrow the crude oil price gap by up to

$4 per barrel; and (ii) provide junior producers with a more affordable option to move their crude oil to market.

On December 11, 2018, the Government of Alberta announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. Little is known about this strategy, but the deadline for interested parties to submit Expressions of Interest was February 8, 2019, and an internal governmental committee is currently reviewing such submissions.

Natural gas prices in Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of LNG export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

Legislation and Regulation

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of Surge in a manner materially different than they would affect other oil and natural gas producers of similar size. All current legislation is a matter of public record and Surge is unable to predict what additional legislation or amendments may be enacted. Some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry are described further below.

Pricing and Marketing – Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

On July 6, 2012, the federal government enacted the *Jobs, Growth and Long-term Prosperity Act* which made amendments to the *National Energy Board Act* ("**NEB Act**") that affect the NEB's export and import framework. As a result of these changes, the NEB issued the Interim Memorandum of Guidance Concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act* ("**Interim Oil and Gas MOG**"). The purpose of the Interim Oil and Gas MOG is to provide guidance to applicants until such time as the NEB has completed the review and update of the regulatory framework. As part of the review and update, the NEB is currently proposing amendments to the *National Energy Board Part VI (Oil and Gas) Regulations* and the *National Energy Board Export and Import Reporting Regulations*.

In February 2018, the federal government issued Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts* (Bill C-69), which among other things, proposes changes to the NEB regime. The changes proposed in Bill C-69, if and when adopted into law, do not materially alter the current requirements around oil exports. However, at this stage, it is not certain whether or when the federal government might issue new or revised regulations that might impact the oil export regime currently in place.

Pricing and Marketing – Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations. Natural gas prices in Alberta have been constrained in recent years due to increasing supply in North America, limited access to markets and limited storage capacity.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate an 8.7% short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, the Government of Alberta will, on a monthly basis, direct oil producers producing more than 10,000 bbl/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019 limiting province-wide production of crude oil and crude bitumen to 3.56 million bbl/d—a reduction of approximately 8.7% from the total daily average oil production in Alberta during December 2018. The Government of Alberta indicated that it expected the curtailment rate to gradually drop over the course of 2019. As a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage, the Government of Alberta announced on January 30, 2019, that it would ease the mandatory production curtailment beginning February 1, 2019, increasing the allowable production cap by 75,000 bbl/d to a maximum output of approximately 3.63 million bbl/d. Surge is subject to a curtailment order. Surge deferred capital from the fourth quarter of 2018 and the first quarter of 2019, in part, to comply with the required production cuts.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada

continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

On November 30, 2018, U.S. President Donald Trump, Prime Minister Trudeau, and outgoing Mexican President Enrique Pena Nieto signed an authorization for a new trade deal that will replace NAFTA, referred to as the United States-Mexico-Canada Agreement ("**USMCA**"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the United States it is unclear when the end of the NAFTA era will be. As the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including Surge's business.

As discussed above, at the end of 2018 the Government of Alberta announced a curtailment of Alberta's crude oil and bitumen production for 2019. Curtailment complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, at the current depressed prices, may be reduced. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Trans-Pacific Partnership

Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018 the CPTPP came into force for the first six countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, and Singapore. On January 14, 2019, the CPTPP came into force for Vietnam. While it is uncertain what effect CPTPP will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with countries around the world. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. While it is uncertain what effect CETA or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Extractive Sector Transparency Measures Act

The *Extractive Sector Transparency Measures Act* ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9,000,000 in total liability.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids and sulphur production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

From time to time the governments of the Western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

In addition, the federal government may from time to time provide incentives to the oil and gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, which will provide oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first year deduction of one and a half times the deduction that is otherwise available. The federal government also announced in late 2018 that it will make $1.6

billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for crude oil and natural gas projects related to economic diversification as well as direct funding for clean growth crude oil and natural gas projects.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced from Crown Lands. Producers of oil and natural gas from Crown lands in Alberta are also required to pay a royalty on substances produced from Crown lands.

On May 27, 2010, the Government of Alberta announced changes to the existing royalty framework under the Petroleum Royalty Regulation, 2009 and the Natural Gas Royalty Regulation, 2009 which became effective January 1, 2011 (the "**Alberta Royalty Framework**"). Changes include making the Natural Gas Deep Drilling Program, which adjusts the royalties for deep gas wells, a permanent initiative under the Alberta Royalty Framework. Qualifying wells under the Natural Gas Deep Drilling Program include natural gas wells with gas-oil ratios of greater than 1,800:1 which have been spud or deepened on or after May 1, 2010 and have a true vertical depth greater than 2,000 metres. An Emerging Resources and Technologies Initiative has also been created to encourage new exploration and development from higher cost and more technically challenging resources, such as shale gas, coal seams and horizontal oil and gas wells. In particular, pursuant to the Emerging Resource and Technologies Initiative: (a) coalbed methane wells will receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010; (b) shale gas wells will receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010; (c) horizontal gas wells will receive a maximum royalty rate of 5 percent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and (d) horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

On January 29, 2016, the Alberta government announced changes to the Alberta Royalty Framework. Under the new modern royalty framework (the "**MRF**"), the sliding scale royalty concept will be maintained, but will be achieved with a greater degree of simplicity. The new royalty percentage will be applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells will be charged a flat 5 percent royalty rate until revenues exceed a normalized well cost allowance, which will be based on vertical well depth and lateral length. The calculation of this cost allowance, and other details regarding the various parameters within the new formula under the MRF was announced in 2016 and was fully implemented as of January 1, 2017. Prior to January 1, 2017, the former royalty framework continued to apply to any wells drilled prior to that date, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF.

In addition to any negotiated royalty amount payable to the freehold mineral owner, producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual

unit values, a default price is supplied by the Crown. On average, the tax levied is 4 percent of revenues reported from fee simple mineral title properties.

Any changes to the royalty regime in Alberta may have a material effect on Surge. See "*Risk Factors - Royalty Regimes.*"

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government.

For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently.

Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil means oil produced within the southwest area that is produced from an oil or gas well with a finished drilling date on or after February 9, 1998 or incremental waterflood oil that commenced operation after February 9, 1998. Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded water flood projects with a commencement date on or after February 9, 1998 and before October 1, 2002, and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded water flood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for freehold "new oil" and freehold "third tier oil" and 12.5 for freehold "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at various reference well production rates (m^3 per month) for old oil, new oil, third tier oil and fourth tier oil. Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier oil, 10 percent for heavy oil that is third tier oil or new oil, 12.5 percent for southwest designated oil that is third tier oil or new oil, 15 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20 percent for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30 percent for all fourth tier oil, 25 percent for heavy oil that is third tier oil or new oil, 35 percent for southwest designated oil that is third tier oil or new oil, 35 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45 percent for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government (effective February 1, 2012), the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act*, *2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations*, *2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, *2012* which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

Base royalty rates are 5 percent for all fourth tier gas, 15 percent for third tier or new gas, and 20 percent for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30 percent for all fourth tier gas, 35 percent for third tier and new gas, and 45 percent for old gas. The current regulatory scheme provides for certain differences with respect to the administration of fourth tier gas which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002 providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013 providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002 whereby incremental production from approved water flood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005 providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005 providing a Crown royalty of 1 percent of gross revenues on EOR projects pre-payout and 20 percent of EOR operating income post-payout and a freehold production tax of 0 percent pre-payout and 8 percent post-payout on operating income from EOR projects; and

- Royalty/Tax Regime for High Water-Cut Oil Wells designed to extend the producing lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5 percent for oil produced prior to April 2013 and 2.25 percent for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to all existing licensed wells and facilities as of July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 10 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Climate Change Regulation

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**"), which was entered into in order work towards stabilizing atmospheric concentrations of greenhouse gas ("**GHG**") emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC came into force on March 21, 1994. On December 12, 2015, the UNFCCC adopted the Paris Agreement, which Canada ratified on October 5, 2016. Under the Paris Agreement, countries have committed to an ambitious goal of holding the increase in global average temperature to well below 2°C

above pre-industrial levels, while they pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreement and establishing a transparency framework related to, among other matters, emissions and climate finance reporting.

In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC Secretariat, pledging a 30 percent reduction from 2005 levels—approximately 523 Mt—by 2030. In addition, provincial/territorial and federal leaders met and agreed that they would work together to build a national climate change plan. At a follow-up meeting of the First Ministers and Prime Minister on March 3, 2016, the parties agreed under the Vancouver Declaration on Clean Growth and Climate Change to launch a process to develop the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"), which was released on December 9, 2016 at the First Ministers meeting. Saskatchewan was the only province that decided not to adopt the Framework.

Prior to the release of the Framework, the federal government announced in October 2016 that it will set a minimum price on carbon starting at $10 per tonne of CO_2e in 2018, which will increase by $10 per year until it reaches $50 per tonne of CO_2e by 2022. This approach will be reviewed in 2022 to confirm the path forward, including continued increases in stringency. Under the federal plan, each province and territory will be required to implement carbon pricing in its jurisdiction by 2018, whether in the form of a carbon tax or a cap-and-trade system. If the carbon price in a jurisdiction does not meet the federal minimum price, the federal government will step in and impose a carbon price that makes up the difference and return the revenue to the province or territory. In addition, provincial and territorial goals for reducing emissions must be at least as stringent as federal targets. Seven provinces and territories have introduced carbon-pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario and New Brunswick in April 2019; it will take effect in the Yukon and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime; and New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 Mt by 2030.

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement sets out specific commitments on energy development, environmental protection, and Arctic leadership. In particular, Canada and the US have made commitments to reduce methane emissions by 40-45 percent below 2012 levels by 2025 from the oil and gas sector, finalize and implement the second phase of an aligned GHG emission standard for post-2018 model year on-road heavy duty vehicles, phase out fossil fuel subsidies, accelerate clean energy development and foster sustainable energy development.

In December 2017, Environment and Climate Change Canada ("**ECCC**") published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the federal *Greenhouse Gas Reporting Program* ("**GHGRP**"). The Notice with respect to reporting of greenhouse gases for 2017, which was published on December 30, 2017 in Part I of the *Canada Gazette,* outlines the 2017 reporting requirements for GHG-emitting facilities. In December 2017, ECCC published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the GHGRP. Starting with the 2017 reporting year, the GHGRP will apply to a wider range of GHG emitting operations in Canada, as the reporting threshold was lowered from 50,000 tonnes to 10,000 tonnes of CO2e. All facilities that emitted the equivalent of 10,000 tonnes of CO2e in 2017 were required to submit a report by June 1, 2018.

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard ("**CFS**") that would incent the use of a broad range of low carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 Mt of annual reductions in GHG emissions by 2030, as part of efforts to achieve Canada's commitments under the Paris Agreement. On December 13, 2017, ECCC published a regulatory framework on the CFS, which outlines the key design elements for the CFS regulation, including its scope, regulated parties, carbon intensity approach, timing, and potential compliance options such as credit trading. However, the proposed regulations to implement the CFS are not anticipated to be enacted until mid-2019.

Surge will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions. The US Environmental Protection Agency ("**EPA**") is proceeding to regulate GHGs under the *Clean Air Act*. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

Alberta

On July 1, 2007, the *Specified Gas Emitters Regulation* ("**SGER**") came into force under Alberta's *Climate Change and Emissions Management Amendment Act* requiring Alberta facilities which emit more than 100,000 tonnes of GHGs annually ("**Regulated Emitters**") to reduce their GHG emissions intensity by 12 percent (from average 2003-2005 levels). On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy.

Alberta's Climate Leadership Plan was introduced in November 2015 with the following policy objectives: (i) putting a price on GHG emissions; (ii) phasing out coal-generated electricity by 2030; (iii) having 30 percent of electricity be generated from renewable sources by 2030; (iv) capping oil sands emissions to 100 Mt per year; and (v)reducing methane emissions by 45 percent by 2025.

Carbon pricing was identified under the Climate Leadership Plan as a key policy tool for reducing GHG emissions. On January 1, 2017, a carbon levy of $20 per tonne of CO_2e was implemented and applies to all heating and transportation fuels. The carbon levy increased to $30 per tonne on January 1, 2018. While the levy is anticipated to increase again in 2021 in line with the federal legislation, the Government of Alberta has announced it will not proceed with the scheduled 2021 increase unless the expansion to the Trans Mountain Pipeline proceeds.

On January 1, 2018, the *Carbon Competitiveness Incentive Regulation* ("**CCI Regulation**") replaced the *Specified Gas Emitters Regulation*. Under the CCI Regulation, facilities are allowed to emit a certain amount of GHG, free of charge from the carbon levy. This approach is designed to protect industries from competitiveness impacts that could shift production to other jurisdictions. The CCI Regulation applies to facilities that emitted 100,000 tonnes or more of GHG in 2003, or a subsequent year. A facility with less than 100,000 tonnes of GHG may be eligible to opt-in to the CCI Regulation if it competes against a facility regulated under the CCI or has more than 50,000 tonnes of annual emissions, high emissions-

intensity and trade-exposure (by opting in, facilities become exempt from the application of the carbon levy for fuels whose emissions are included in their site reporting). Under the updated system, a facility will receive performance credits if its GHG emissions are less than the amount freely permitted. If its emissions are above the amount freely permitted, they will be required take one or more of the following actions to bring the facility into compliance:

- make improvements at their facility to reduce emissions intensity;
- use emission performance credits generated at facilities that achieve more than the required reductions;
- purchase Alberta-based carbon offset credits; or
- contribute to Alberta's Climate Change and Emissions Management Fund.

Emissions from the oil sands sector (which account for approximately one-quarter of Alberta's annual emissions) have been capped at 100 Mt per year. This cap has been legislated in the *Oil Sands Emissions Limit Act* (Bill 25), which was introduced in November 2016. The legislation contemplates certain exceptions in respect of cogeneration emissions, upgrading emissions, and potential discretionary exemptions by regulation (likely to accommodate new technological developments). Bill 25 came into force on December 14, 2016.

In January 2018, the Alberta government also announced that it is adopting ECCC's GHG reporting requirements for the 2017 reporting period, meaning that facilities emitting 10,000 tonnes of CO_2e or more must submit a specified gas report to Alberta Climate Change Office via ECCC's SWIM reporting system (the reporting threshold for previous years is 50,000 tonnes of CO_2e). Facilities were required to report their 2017 greenhouse gas emissions to ECCC's SWIM system by June 1, 2018.

Saskatchewan

In October 2016, Saskatchewan released its Climate Change White Paper, which outlined the principles of the province's approach to climate change, including a focus on both mitigation and adaptation responses to climate change. Following the release of the White Paper, the government worked on developing its comprehensive climate change strategy, which was released in December 2017: Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy (the "**Strategy**"). The Strategy focuses on the principles of readiness and climate resilience, curbing GHG emissions, and preparing for changing conditions such as extreme weather, drought or wildfire. Saskatchewan has decided not to sign on to the Pan-Canadian Framework on Clean Growth and Climate Change or to adopt a carbon pricing mechanism, meaning that it will be out of compliance with federal requirements. The Strategy proposes actions in key areas, including (i) natural systems; (ii) physical infrastructure; (iii) economic sustainability; (iv) community preparedness; and (v) measuring, monitoring and reporting. Although no specific emission reduction targets are set out in the Strategy, the Saskatchewan government has indicated that it will support Canada's efforts to meet national commitments under the Paris Agreement. Prior to the release of the Strategy, Saskatchewan relied on the GoGreen Saskatchewan initiative to encourage the reduction of GHG emissions and to educate the public about climate change. Between 2008 and 2015, the Saskatchewan government estimates that it invested $60 million in GoGreen funding through public/private partnerships.

Saskatchewan has also identified technology as a key driver of emission reductions, including carbon capture use and storage as well as renewable energy. In 2015, SaskPower set a target of doubling its percentage of electricity capacity from renewable energy sources, i.e. to have 50 percent of the province's power sourced from renewables by 2030.

As part of the Strategy, Saskatchewan will develop annual GHG reporting regulations for facilities that emit more than 25,000 tonnes of CO_2e annually (with a voluntary opt-in for emitters over 10,000 tonnes of CO_2e annually).

Land Tenure

Crude oil and natural gas located in the Western Canadian provinces is owned both by the respective provincial governments and by private individuals. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying periods and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Where oil and natural gas is privately owned, rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80 percent of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. In 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve shallow rights reversion notices.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emitting of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory abandonment and reclamation of well and facility sites and provides form among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations, habitat protection and minimum setbacks of oil and gas activities from fresh water bodies. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. Certain environmental protection legislation may subject Surge to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge. Further, as Canadian environmental legislation evolves, the use of administrative penalties by the imposition of fines for the commission of environmental offences on an absolute liability basis has grown.

Environmental legislation is evolving in a manner that has and is expected to continue to result in stricter standards and enforcement, larger fines, liabilities and sanctions, and potentially increased capital expenditures and operating costs. To mitigate potential environmental liabilities, Surge in addition to implementing policies and procedures designed to prevent an accidental spill or discharge, maintains insurance at industry standards.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act* and the *Canadian Environmental Assessment Act*, provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On February 8, 2018, the Government of Canada introduced Bill C-69, draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("**CER**"). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. Additional categories of projects may be included within new impact assessment process, such as largescale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. Many of the CER's activities would be similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The effects of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced Bill C-48 (the *Oil Tanker Moratorium Act*), in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* ("**EPEA**"), the *Water Act* and the *Oil and Gas Conservation Act* ("**ABOGCA**"). EPEA, the *Water Act* and the ABOGCA impose strict environmental standards with respect to releases of effluents and emissions, require stringent compliance, reporting and monitoring obligations, and impose significant penalties for non-compliance.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the ABOGCA. On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Parks ("**AEP**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AEP in the areas of environment and water under EPEA and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land, and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 percent of the province's oilsands resources and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access.

The South Saskatchewan Regional Plan ("**SSRP**") was approved by the Government of Alberta on July 23, 2014 and became effective on September 1, 2014. The SSRP is the second regional plan developed under the ALUF and covers approximately 83,764 square kilometres and includes 44 percent of the province's population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, oil and gas companies must nonetheless minimize impacts of activities on the natural landscape, historic resources, wildlife, fish

and vegetation when exploring, developing and extracting the resources. Any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. Freehold mineral rights will not be subject to this restriction. With the implementation of the new Alberta regulatory structure under the AER, AEP will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Saskatchewan

Saskatchewan's Ministry of the Economy and the Oil and Gas Conservation Board collectively regulate oil and gas activities in the province, which is primarily governed by the *Natural Resources Act* and *The Oil and Gas Conservation Act* ("**SKOGCA**").

The Environmental Management and Protection Act ("**EMPA**") regulates the protection of the environment in Saskatchewan, including among others the designation of environmentally impacted sites, issuance of environmental protection orders, and obligations to report releases of substances. Most importantly, the EMPA prohibits the discharge of substances causing adverse effects to the environment, and assigns responsibility for such adverse effects to a broad category of "persons responsible." This includes the person who caused or contributed to the discharge (i.e. fugitive release of sour gas or flaring in excess of the permitted levels), had possession or control of the substance, as well as every owner and occupier of the land, including subsequent owners and occupiers and any person transporting the substance.

In May 2011, Saskatchewan passed changes to SKOGCA. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers, and procedural aspects, including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards will apply to existing licensed wells and facilities on July 1, 2015.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**") as part of the Liability Management Rating Assessment Process. The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan well fund (the "**Orphan Well Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Well Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Well Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. In short, the AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (and therefore the licensee has a resulting LLR of less than 1.0) to provide the AER with a security deposit. In certain

circumstances, for example during the transfer of AER licenses between parties, the AER will require that the transferee must achieve an LLR of 2.0 or higher immediately following the proposed transfer of the applicable licenses. The ratio of deemed liabilities to deemed assets is assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit may result in the initiation of enforcement actions by the AER.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which was affirmed by a majority at the Alberta Court of Appeal. In Redwater Energy Corporation (Re), 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act* (Alberta) and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA.

The AER issued several bulletins in response to Redwater. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. The AER's Directive 67 was amended and now requires extensive corporate governance and shareholder information, with a focus on any previous insolvency proceedings in order to acquire or transfer licenses needed to operate wells and facilities. The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold EUB Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee eligibility approval if appropriate in the circumstances. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer. The AER may implement additional changes in response to the final Redwater decision.

The AER implemented the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20 percent of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76 percent of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19 percent of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

On January 31, 2019, the Supreme Court of Canada ruled on the appeal of Redwater in *Orphan Well Association v. Grant Thornton Limited,* 2019 SCC 5 in favour of the AER and Orphan Well Association. Specifically, the SCC held that while trustees will not be personally liable for abandonment and reclamation obligations, the estate will remain liable for such obligations. As a result, reclamation and abandonment liabilities must be dealt with before there can be any distribution to the insolvent parties' creditors, including its secured creditors. In response to the SCC's decision, the AER is working on an improved liability management framework. Surge cannot predict what the AER's improved framework may look like but such pending changes to the AB LLR Program will have an impact on crude oil and natural gas production in Alberta, including Surge's business.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan well fund (the "**Oil and Gas Orphan Well Fund**"). The Oil and Gas Orphan Well Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed each month for all licensees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators that it would follow the AER's interim rules by processing all licence transfer applications as non-routine until further notice.

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. The following information is a summary only of certain risk factors relating to the Corporation and should be read in conjunction with the detailed information appearing elsewhere in this Annual Information Form. Prospective investors should carefully consider the risk factors set out below and consider all other information contained in this Annual Information Form and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Operational Risks

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. In accordance with industry practice, Surge is not fully insured against all of these risks, nor are all such risks insurable. Although Surge maintains liability insurance in an amount which it considers adequate, the nature of these risks is such that liabilities could exceed policy limits, in which event Surge could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Surge and may delay exploration and development activities.

Oil and natural gas exploration and development activities are dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Unexpected adverse weather conditions, such as flooding or prolonged break-up, can have a significant negative impact on capital expenditures, operations and costs.

To the extent Surge is not the operator of its oil and natural gas properties, it is dependent on such operators for the timing of activities related to such properties and is largely unable to direct or control the activities of the operators. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although Surge intends to operate the majority of its properties, there is no guarantee that it will remain operator of such properties or that Surge will operate other properties it may acquire in the future.

In addition, the success of Surge will be largely dependent upon the performance of its management and key employees. Surge does not have any key man insurance policies and, therefore, there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Surge.

Surge's ability to market oil and natural gas from its wells also depends upon numerous other factors beyond its control, including, among other things, the availability of natural gas processing and storage capacity, the availability of pipeline capacity, the price of oilfield services and the effects of inclement weather. Because of these factors, Surge may be unable to market some or all of the oil and natural gas it produces or to obtain favourable prices for the oil and natural gas it produces.

Volatility of Oil and Natural Gas Prices and Markets

Surge's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on Surge's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global and North American supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of Surge including, but not limited, to the world economy and the Organization of Petroleum Exporting Countries' ("**OPEC**") ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. In addition, the prices received by Surge for its oil are subject to differentials against such benchmarks as WTI and Edmonton Par which can fluctuate substantially and result in Surge realizing prices substantially below such benchmarks. Oil and natural gas producers in Western Canada may receive significantly discounted prices for some of their production due to regional constraints on their ability to transport and sell such production, including to international markets. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources.

Decreases in oil and natural gas prices realized by Surge will result in reduced net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of Surge's reserves. Any further substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in Surge's net production revenue, cash flows and profitability causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Surge will in part be determined by Surge's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available, including under the Credit Facility, and could require that a portion of its bank debt be repaid.

Surge may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Surge will not benefit from such increases.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by certain changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional

downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the U.S. administration has begun taking steps to implement a certain of its promises made during the campaign. The administration has withdrawn the U.S. from the TPP and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, and Canada, the U.S. and Mexico signed the Canada-United States-Mexico Agreement which will replace NAFTA once ratified by the three signatory countries. See "*Industry Conditions – The North American Free Trade Agreement*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the new U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Surge.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on Surge's ability to market products internationally, increase costs for goods and services required for operations, reduce access to skilled labour and negatively impact business, operations, financial conditions and the market value of the Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy.

Climate Change

Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism, including threats of culpability, legal action against oil and gas producers, and public opposition to fossil fuels and the oil and gas industry in which the Corporation operates. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for climate-related harms.

Public and government hostility toward the oil and gas industry could reduce demand for oil and gas and, therefore, adversely affect market prices for the Corporation's production. Existing and future laws and regulations may impose additional costs on companies operating in the oil and gas industry or significant

liabilities for failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general.

Surge's exploration and production facilities and other operations and activities emit GHGs which may require us to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. The federal carbon levy goes into effect on April 1, 2019 and will affect provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Ontario, Manitoba, Saskatchewan and New Brunswick. The federal carbon levy will be at an initial rate of $20 per tonne. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The implementation of the federal carbon levy is currently subject to constitutional challenges submitted by the Provinces of Saskatchewan and Ontario, which are supported by the Province of New Brunswick. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses and in the long-term reducing the demand for oil and natural gas production, resulting in a decrease in our profitability and a reduction in the value of our assets or asset write-offs.

See "*Industry Conditions – Climate Change Regulation*".

Environmental Concerns

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Surge may be in noncompliance with an environmental law, regulation, permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Surge to fines or penalties, third party liabilities or to the requirement to remediate, which could be material.

The operational hazards associated with possible blowouts, accidents, oil spills, natural gas leaks, fires, or other damage to a well or a pipeline may require Surge to incur costs and delays to undertake corrective actions, could result in environmental damage or contamination or could result in serious injury or death to employees, consultants, contractors or members of the public, creating the potential for significant liability to Surge. Also, the occurrence of any such incident could damage Surge's reputation in the surrounding communities and make it more difficult for Surge to pursue its operations in those areas.

Compliance with environmental laws and regulations could materially increase Surge's costs. Surge may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, Surge may be required to incur significant costs to comply with future federal or provincial greenhouse gas emissions reduction requirements or other regulations, if enacted. See "*Industry Conditions – Environmental Regulation*".

The oil and natural gas industry elicits concerns about climate change, as well as general public opposition to the industry. As a result, industry participants may be subject to increased public activism, which could result in increased costs due to delays or damage.

Although Surge maintains insurance consistent with prudent industry practice, it is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, Surge's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Surge.

Dividends

Notwithstanding anything contained in this Annual Information Form, the payment and the amount of dividends declared, if any, will be subject to the discretion of the Board and will depend on the Board's assessment of the Corporation's outlook for growth, capital expenditure requirements, funds from operations, potential opportunities, debt position and other conditions that the Board may consider relevant at such future time, including applicable restrictions that may be imposed under the Credit Facility and on the ability of the Corporation to pay dividends. The amount of future cash dividends, if any, may also vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates. To the extent that external sources of capital become limited or unavailable, Surge's ability to make the necessary capital investments to maintain or expand oil and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that Surge is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

In addition, the market value of the Common Shares may decline if the Corporation's cash dividends decline in the future, and that market value decline may be material. See "*Dividend Policy*."

Royalty Regimes

There can be no assurance that the federal government and the provincial governments in the jurisdictions in which the Corporation operates will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. The royalty regime in Alberta, Saskatchewan and any other jurisdictions in which the Corporation's oil and natural gas assets are located may be subject to further review and changes which could adversely impact the Corporation's financial condition and operations. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See "*Industry Conditions - Provincial Royalties and Incentives*".

Gathering and Processing Facilities, Pipeline Systems and Rail

Surge delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that Surge can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. Notwithstanding the Government of Alberta's plans to purchase or lease 4,400 rail cars and the implementation of production curtailment in Alberta, the ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the inability to realize the full economic potential of Surge's production or in a reduction of the price offered for its production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect Surge's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and

facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm Surge's business and, in turn, its financial condition, operations and cash flows. Announcements and actions taken by the federal government and the Government of Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of Surge's production may, from time to time, be processed through facilities owned by third parties and over which it does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on Surge's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Fixed Price Hedging

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Industry Regulation and Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Surge will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in

all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Surge. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw. Surge's ability to increase reserves and production in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling.

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond the control of Surge. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing, transportation and royalty rates) are subject to extensive controls and regulations imposed by various levels of government, including those described above under the heading "Industry Conditions", which may be amended from time to time. Surge's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Changes to the regulation of the oil and gas industry in jurisdictions in which Surge operates may adversely impact Surge's ability to economically develop existing reserves and add new reserves.

Variations in Foreign Exchange Rates and Interest Rates

Surge's expenses will be denominated in Canadian dollars, while the price of oil and natural gas will generally be denominated in U.S. dollars or impacted by the Canadian dollar to U.S. dollar exchange rate. As the exchange rate for the Canadian dollar versus the U.S. dollar increases, Surge will generally receive fewer Canadian dollars for its production. If the value of the Canadian dollar against the U.S. dollar increases, the financial results of Surge may be negatively affected. Future fluctuations in the Canadian/United States foreign exchange rate may impact the future value of Surge's reserves as determined by independent evaluators. In addition, variations in interest rates could result in a significant change in the amount Surge will pay to service debt, potentially adversely affecting the value of the Common Shares. Surge's management may hedge interest rates to mitigate these risks.

Price Volatility of Publicly Traded Securities

In recent years, the securities markets in Canada and the United States have experienced a high level of price and volume volatility, and the market price of securities of many companies, particularly those considered to be development stage companies, has experienced wide fluctuations in price which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies. There can be no assurance that continual fluctuations in price will not occur. It is likely that the market price for the Common Shares will be subject to market trends generally, notwithstanding the financial and operational performance of Surge.

Abandonment and Reclamation Costs

As a general rule, the current oil and gas asset abandonment, reclamation and remediation ("**A&R**") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. In the case where one joint owner of an oil and gas asset becomes insolvent and is unable to fund the required A&R activities associated with such asset, the solvent working interest counterparties can recover the insolvent party's share of the remediation costs from the Orphan Well Fund. See "*Industry Conditions – Liability Management Ratings Programs*".

As a result of the Supreme Court of Canada's January 2019 decision in the *Redwater* case, a trustee in bankruptcy is not permitted to renounce uneconomic oil and gas assets and leave these assets to be remediated by the Orphan Well Fund, thereby avoiding the environmental liabilities of the estate it is administering. Accordingly, the AER may now use Alberta's provincial legislative scheme to prevent the repudiation or renunciation of an insolvent company's assets by a trustee and require the trustee to

satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors. In response to the Supreme Court's decision, the AER is also working on an improved liability management framework. Surge cannot predict what the AER's improved framework may look like but such pending changes to the AB LLR Program will have an impact on crude oil and natural gas production in Alberta, including Surge's business.

The AER's new liability management framework may impact the Corporation's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs and delays or require changes to or abandonment of projects and transactions. As a result of the decision in Redwater, lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Corporation. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Corporation, and the associated A&R liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent A&R-related operational covenants, and may increase the cost of providing credit.

The Supreme Court decision in Redwater also could make the transfer of oil and gas assets from insolvent parties more challenging if a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process. The result could be additional liabilities being placed upon the Orphan Well Fund. The Orphan Well Fund may seek funding for such liabilities from industry participants, including the Corporation, through an increase in its annual levy, further changes to regulations, or other means. While the impact on the Corporation of any legislative, regulatory or policy decisions as a result of the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Corporation and materially and adversely affect, among other things, the Corporation's business, financial condition, results of operations and cash flow.

Credit Facility Risks

The Corporation currently has the Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions on the Corporation that could include restrictions on the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See "*Industry Conditions – Liability Management Rating Programs*".

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Substantial Capital Requirements; Liquidity

Surge may have to make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If revenues or reserves decline, Surge may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the company. Moreover, future activities may require Surge to alter its capitalization significantly. The inability of the company to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects.

Reserve Estimates

There are numerous uncertainties inherent in evaluating quantities of reserves and the net present value of future net revenue to be derived therefrom, including many factors beyond the control of Surge. The reserves information contained in the Reserves Report and set forth herein, including information respecting the net present value of future net revenue from reserves, represents an estimate only. This estimate is based on a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the Reserve Reports were prepared and many of these assumptions are subject to change and are beyond the control of Surge. Ultimately, the actual reserves attributable to Surge's properties will vary from the estimates contained in the Reserves Report and those variations may be material and affect the market price of the Common Shares.

Reserve Replacement

Surge's future oil and natural gas reserves and production and the cash flows to be derived therefrom are highly dependent on successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Surge may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in reserves will depend not only on Surge's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Surge's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Sour Natural Gas

Some of the Corporation's current or future properties include wells that produce sour natural gas and facilities that process sour natural gas. An accidental discharge or leak of sour natural gas can be fatal or cause serious injury. The dangers associated with drilling for, producing, processing and transporting sour natural gas necessitate increased environmental, health and safety compliance costs to Surge and any accidental discharge or leak of sour natural gas could lead to significant liabilities to Surge. Surge has implemented policies and protocols to address this risk, but it is not possible for any issuer to eliminate all of the risks associated with producing, processing and transporting sour natural gas.

Delay in Cash Receipts and Credit Worthiness of Counterparties

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Surge's properties, and by the operator to Surge, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Surge's properties or the establishment by the operator of reserves for such expenses. In addition, the insolvency or financial impairment of any counterparty owing money to Surge, including industry partners and marketing agents, could prevent Surge from collecting such debts.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Issuance of Debt

From time to time Surge may enter into transactions to acquire assets or shares of other corporations. These transactions may be financed partially or wholly through debt, which may increase debt levels above industry standards. Surge's articles and by-laws do not limit the amount of indebtedness it may incur. The level of Surge's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Possible Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation has recently completed a number of acquisitions and dispositions and may complete future acquisitions and dispositions to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, among other things, potential cost savings. Achieving the benefits of recent and any future acquisitions the Corporation may complete will depend in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Corporation. The integration of acquired assets requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of recent and any future acquisitions. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of Surge's non-core assets may realize less on disposition than their carrying value on the consolidated financial statements of the Corporation.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that Surge will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If Surge implements such technologies, there is no assurance that it will do so successfully. One or more of the technologies currently utilized by Surge or implemented in the future may become obsolete. In such case, Surge's business, financial condition and results of operations could be affected adversely and materially. If Surge is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, Surge's business, financial condition and results of operations could also be adversely affected in a material way.

Information Technology Systems and Cyber-Security

Surge has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations. Surge depends on various information technology systems to estimate reserve quantities, process and record financial data, manage the land base, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third-party partners.

Further, Surge is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of its information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to Surge's business activities or competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on Surge's performance and earnings, as well as on Surge's reputation. Surge has technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on Surge's business, financial condition and results of operations.

Hydraulic Fracturing

The proliferation of the use of hydraulic fracturing as a recovery technique employed in oil and natural gas drilling has given rise to increased public scrutiny of its environmental aspects, particularly with respect to its potential impact on local aquifers. Surge utilizes hydraulic fracturing in a significant portion of the light oil wells it drills and completes. Negative public perception of hydraulic fracturing may place pressure on governments in the jurisdictions where Surge operates to implement additional regulatory requirements or limitations on the utilization of hydraulic fracturing, which in turn could restrict Surge's operations and increase its costs.

Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Surge is ultimately able to produce from its reserves.

Dilution

Common Shares, including rights, warrants, special warrants, subscription receipts and other securities to purchase, to convert into or to exchange into Common Shares, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board may determine. In addition, Surge may issue additional Common Shares from time to time pursuant to Surge's stock option plan and stock incentive plan. The issuance of these Common Shares would result in dilution to holders of Common Shares.

Net Asset Value

Surge's net asset value will vary depending upon a number of factors beyond the control of Surge's management, including oil and natural gas prices. The trading price of the Common Shares is also determined by a number of factors which are beyond the control of management and such trading price may be greater than or less than the net asset value of Surge.

Reliance on Management

Shareholders will be dependent on the management of Surge in respect of the administration and management of all matters relating to Surge and its properties and operations. Investors who are not willing to rely on the management of Surge should not invest in Common Shares.

Permits and Licenses

The operations of Surge may require licenses and permits from various governmental authorities. There can be no assurance that Surge will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat a claim of Surge which could result in a reduction of Surge's interest in a property or well and the revenue received by Surge therefrom.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to resources and various properties in Western Canada. Such claims, in relation to any of Surge's lands, if successful, could have an adverse effect on its operations.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Corporate Matters

Certain of the directors and officers of Surge are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of Surge, as the case may be, and as officers and directors of such other companies.

Failure to Maintain Listing of the Common Shares and the Debentures

The Common Shares and the Debentures are currently listed for trading on the facilities of the TSX. The failure of Surge to meet the applicable listing or other requirements of the TSX in the future may result in the Common Shares and/or the Debentures ceasing to be listed for trading on the TSX, which would have a material adverse effect on the value of the Common Shares and/or Debentures. There can be no assurance that the Common Shares and Debentures will continue to be listed for trading on the TSX.

Structure of Surge

From time to time, Surge may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of Surge and its subsidiaries. If the manner in which Surge structures its affairs is successfully challenged by a taxation or other authority, Surge and the holders of Common Shares may be adversely affected.

Changes in Legislation

It is possible that the Canadian federal and provincial government or regulatory authorities could choose to change the Canadian federal income tax laws, royalty regimes, liability management, environmental and climate change laws or other laws applicable to oil and gas companies and that any such changes could materially adversely affect Surge, its shareholders and the market value of the Common Shares.

Additional information on the risks, assumptions and uncertainties are found in this Annual Information Form under the heading "*Special Note Regarding Forward Looking Statements*".

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. Surge cannot predict the impact of changing

demand for oil and natural gas products, and any major changes may have a material adverse effect on its business, financial condition, results of operations and cash flows by decreasing profitability, increasing costs, limiting access to capital and decreasing the value of Surge's assets.

Forward-Looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on Surge's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Special Note Regarding Forward Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2018, there were (i) no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that it believes would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Each of James Pasieka, a director of the Corporation, and Michael Bennett, the Corporate Secretary of the Corporation, is a partner of the national law firm McCarthy Tétrault LLP, which law firm renders legal services to the Corporation.

Except as disclosed above or as may be disclosed elsewhere in this AIF, none of the directors, executive officers or principal shareholders of the Corporation, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect the Corporation or any of its affiliates.

AUDITOR, TRANSFER AGENT AND REGISTRAR

KPMG LLP are the auditors of the Corporation and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF EXPERTS

The Reserves Report and certain reserves estimates contained in filings made by the Corporation under National Instrument 51-102 – Continuous Disclosure Requirements during the year ended December 31, 2018 were prepared by Sproule. As at the date of this Annual Information Form, the directors, officers, employees and consultants of Sproule who participated in the preparation of the Reserves Report or such reserves estimates or who were in a position to directly influence the preparation or outcome of the

preparation of the Reserves Report or such reserves estimates, as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares.

KPMG LLP are independent of the Corporation pursuant to the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information concerning the Corporation may be found under the Corporation's profile on SEDAR at www.sedar.com. Additional information, including information concerning directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, will be contained in the information circular of the Corporation for the annual general meeting of the holders of Common Shares scheduled to be held in 2019. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2018.

SCHEDULE "A"

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Surge Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2018, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	December 31, 2018	Canada				
Total			**Nil**	**2,053,553**	**Nil**	**2,053,553**

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Surge Energy Inc. (As of December 31, 2018)".

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 27, 2019

Original Signed by Matthew J. Tymchuk, P.Eng.

Matthew J. Tymchuk, P.Eng.
Manager, Engineering

Original Signed by Brent A. Hawkwood, C.E.T.

Brent A. Hawkwood, C.E.T.
Senior Technologist

Original Signed by Tom D. Holmwood, P.Eng.

Tom D. Holmwood, P.Eng.
Senior Petroleum Engineer

Original Signed by Tamara Warren, P.Eng.

Tamara Warren, P.Eng.
Petroleum Engineer

Original Signed by Ian K. Kirkland, P.Geol.
on behalf of Maren L. Blair, P.Geol.

Maren L. Blair, P.Geol.
Senior Geologist

Original Signed by Ian K. Kirkland, P.Geol.

Ian K. Kirkland, P.Geol.
Senior Geologist

Original Signed by Victor Verkhogliad, P.Geol.
on behalf of Alec Kovaltchouk, P.Geo.

Alec Kovaltchouk, P.Geo.
VP, Geoscience

Original Signed by Nora T. Stewart, P.Eng.

Nora T. Stewart, P.Eng.
Senior VP, Reserves Certification and Director

SCHEDULE “B”

FORM 51-101F3
Report of Management and Directors on Reserves Data and Other Information

Terms to which a meaning is ascribed in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Surge Energy Inc. (the “**Corporation**”) are responsible for the preparation and disclosure of information with respect to the Corporation’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

Sproule Associates Limited, an independent qualified reserves evaluator, has evaluated and reviewed the Corporation’s reserves data. The report of the independent qualified reserves evaluator is presented in Schedule ”A” to the Annual Information Form of the Corporation for the year ended December 31, 2018 (the “**AIF**”).

The Reserves Committee of the Board of Directors of the Corporation has:

(a) reviewed the Corporation’s procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the applicable reserves data with management and with Sproule Associates Limited.

The Reserves Committee of the Board of Directors has reviewed the Corporation’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1, incorporated into the AIF, containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "Paul Colborne"	*(signed) "Rod Monden"*
Paul Colborne, President & Chief Executive Officer	Rod Monden, Controller
(signed) "Daryl Gilbert"	*(signed) "P. Daniel O'Neil"*
Daryl Gilbert, Director & Chair of the Reserves Committee	P. Daniel O'Neil, Director

March 12, 2019

SCHEDULE "C"

Audit Committee Charter

Role and Objective

The Audit Committee is a committee of the Board of Directors of Surge Energy Inc. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited consolidated financial statements and other mandatory disclosure releases containing financial information of the Corporation. The objectives of the Audit Committee are as follows:

1. to assist directors in fulfilling their legal and fiduciary obligations (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to oversee the audit efforts of the external auditors of the Corporation;

3. to maintain free and open means of communication among the directors, the external auditors, the financial and senior management of the Corporation;

4. to satisfy itself that the external auditors are independent of the Corporation; and

5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

The function of the Committee is one of oversight of management and the external auditors in the execution of their responsibilities. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation, maintaining appropriate accounting and financial reporting principles and policies and implementing appropriate internal controls and procedures. The external auditors are responsible for planning and carrying out a proper audit of the annual financial statements of the Corporation and reviewing the interim financial statements of the Corporation prior to their filing with securities regulatory authorities and other procedures.

Composition of the Committee

1. The Audit Committee shall consist of at least three directors. The Board shall appoint one member of the Audit Committee to be the Chair of the Audit Committee.

2. Each director appointed to the Audit Committee by the Board must be independent. A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to National Instrument 52-110 – Audit Committees or the then current legislation, rules, policies and instruments of applicable regulatory authorities.

3. Each member of the Audit Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.

4. A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

Meetings of the Committee

1. The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or a senior officer of the Corporation. Meetings of the Audit Committee shall correspond with the review of the quarterly financial statements and management discussion and analysis of the Corporation.

2. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee. The auditors shall be given notice of each meeting of the Audit Committee at which financial statements of the Corporation are to be considered and such other meetings as determined by the Chair and shall be entitled to attend each such meeting of the Audit Committee.

3. Notice of a meeting of the Audit Committee shall:

    (a) be in writing;

    (b) state the nature of the business to be transacted at the meeting in reasonable detail;

    (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and

    (d) be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.

4. A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee. However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.

5. A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

6. In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

7. The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management as necessary, in the sole discretion of the Committee, but in any event, not less than quarterly; and (ii) may meet separately with management.

8. Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

Duties and Responsibilities of the Committee

1. It is the responsibility of the Audit Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Audit Committee.

2. The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board or the legislation, policies or regulations governing the Corporation and its business.

3. It is the responsibility of the Audit Committee to satisfy itself on behalf of the Board that the Corporation's system of internal controls over financial reporting and disclosure controls and procedures are satisfactory for the purpose of:

   (a) identifying, monitoring and mitigating the principal risks;

   (b) ensuring compliance with legal, ethical and regulatory requirements;

   and to review with the external auditors their assessment of the internal controls over financial reporting and the disclosure controls of the Corporation, their written reports containing recommendations for improvement, and management's response and any follow-up to any identified weaknesses.

4. It is the responsibility of the Audit Committee to review the annual financial statements of the Corporation and, if deemed appropriate, recommend the financial statements to the Board for approval. This process should include but be not to be limited to:

   (a) reviewing and accepting, if appropriate, the annual audit plan of the external auditors of the Corporation, including the scope of audit activities, and monitor such plan's progress and results during the year;

   (b) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

   (c) reviewing significant accruals, reserves or other estimates such as any impairment calculation;

   (d) reviewing the methods used to account for significant unusual or non-recurring transactions;

   (e) ascertaining compliance with covenants under loan agreements;

   (f) reviewing disclosure requirements for commitments and contingencies;

   (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   (h) reviewing unresolved differences between management and the external auditors;

   (i) obtain explanations of significant variances with comparative reporting periods;

   (j) review of business systems changes and implications;

   (k) review of authority and approval limits;

   (l) review the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors and management;

   (m) confirm through private discussion with the external auditors and the management that no management restrictions are being placed on the scope of the external auditors' work;

(n) review of tax policy issues; and

(o) review of emerging accounting issues that could have an impact on the Corporation.

5. It is the responsibility Audit Committee to review the interim financial statements of the Corporation and, if deemed appropriate, to recommend the financial statements to the Board for approval and to review all related management discussion and analysis. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.

6. The Audit Committee shall have the authority to:

   (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;

   (b) discuss with the management and senior staff of the Corporation, its subsidiaries and affiliates, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;

   (c) engage independent counsel and other advisors as it determines necessary to carry out its duties; and

   (d) to set and pay the compensation for any advisors employed by the Audit Committee.

7. With respect to the appointment of external auditors by the Board, the Audit Committee shall:

   (a) recommend to the Board the appointment of the external auditors;

   (b) review the performance of the external auditors and make recommendations to the Board regarding the replacement or termination of the external auditors when circumstances warrant;

   (c) oversee the independence of the external auditors by, among other things, requiring the external auditors to deliver to the Audit Committee, on a periodic basis, a formal written statement delineating all relationships between the external auditors and the Corporation and its subsidiaries;

   (d) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee; and

   (e) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

8. Audit Committee shall review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

9. The Audit Committee must pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by external auditors. The Audit Committee may delegate, to one or more members, the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting and such pre-approval and the member comply with such other procedures as may be established by the Audit Committee form time to time.

10. The Audit Committee shall review the risk management policies and procedures of the Corporation (i.e. hedging, litigation and insurance), including the annual review of insurance coverage and make appropriate recommendations to the Board with respect thereto.

11. The Audit Committee shall receive regular updates with respect to information technology matters, including with respect to the Corporation's cyber security programs to address potential cyber-related risks.

12. The Audit Committee shall establish and maintain procedures for:

    (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting controls, or auditing matters; and

    (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

13. The Audit Committee shall review and approve the Corporation’s hiring policies regarding employees and former employees of the present and former external auditors or auditing matters.

14. The Chairman of the Audit Committee shall review and approve the expenses incurred by the President and Chief Executive Officer.

15. The Audit Committee shall periodically report the results of reviews undertaken and any associated recommendations to the Board.

16. The Audit Committee shall assess, on an annual basis, the adequacy of this Mandate and the performance of the Audit Committee.